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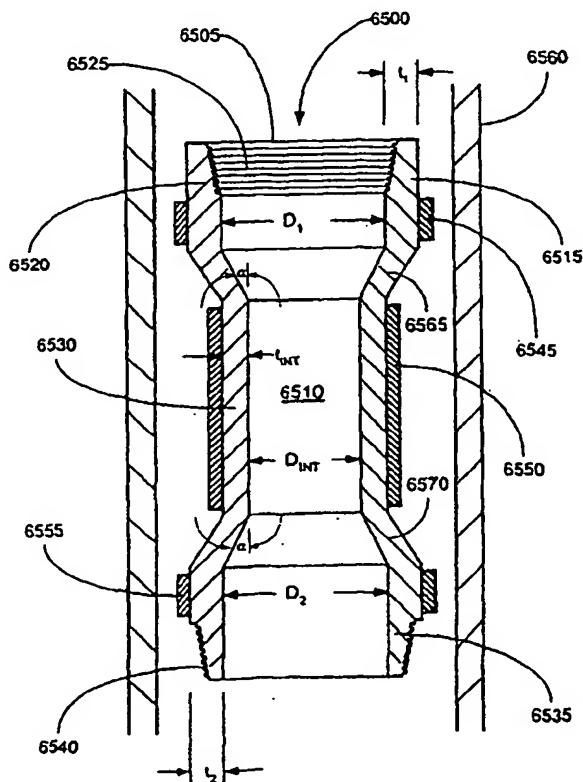
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[Continued on next page]

- (54) Title: TWO-STEP RADIAL EXPANSION



(57) Abstract: A two-step radial expansion process. A first tubular member (6530) is radially expanded into contact with the interior surface of a second tubular member (6550). Both tubular members are then radially expanded.

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TWO-STEP RADIAL EXPANSION

Background of the Invention

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

Conventionally, at the surface end of the wellbore, a wellhead is formed that typically includes a surface casing, a number of production and/or drilling spools, valving, and a Christmas tree. Typically the wellhead further includes a concentric arrangement of casings including a production casing and one or more intermediate casings. The casings are typically supported using load bearing slips positioned above the ground. The conventional design and construction of wellheads is expensive and complex.

Conventionally, a wellbore casing cannot be formed during the drilling of a wellbore. Typically, the wellbore is drilled and then a wellbore casing is formed in the newly drilled section of the wellbore. This delays the completion of a well.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming wellbores and wellheads.

Summary of the Invention

According to one aspect of the present invention, a method of forming a wellbore casing is provided that includes installing a tubular liner and a mandrel in the borehole, injecting fluidic material into the borehole, and radially expanding the liner in the borehole by extruding the liner off of the mandrel.

According to another aspect of the present invention, a method of forming a wellbore casing is provided that includes drilling out a new section of the borehole adjacent to the already existing casing. A tubular liner and a mandrel are then placed into the new section of the borehole with the tubular liner overlapping an already existing casing. A hardenable fluidic sealing material is injected into an annular region between the tubular liner and the new section of the borehole. The annular region between the tubular liner and the new section of the borehole is then fluidically isolated from an interior region of the tubular liner below the mandrel. A non hardenable fluidic material is then injected into the interior region of the tubular liner below the mandrel. The tubular liner is extruded off of the mandrel. The overlap between the tubular liner and the already existing casing is sealed. The tubular liner is supported by overlap with the already existing casing. The mandrel is removed from the borehole. The integrity of the seal of the overlap between the tubular liner and the already existing casing is tested. At least a portion of the second quantity of the hardenable fluidic sealing material is removed from the interior of the tubular liner. The remaining portions of the fluidic hardenable fluidic sealing material are cured. At least a portion of cured fluidic hardenable sealing material within the tubular liner is removed.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, a mandrel, a tubular member, and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member and includes a second fluid passage. The tubular member is coupled to the mandrel. The shoe is coupled to the tubular liner and includes a third fluid passage. The first, second and third fluid passages are operably coupled.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, an expandable mandrel, a tubular member, a shoe, and at least one sealing member. The support member includes a first fluid passage, a second fluid passage, and a flow control valve coupled to the first and second fluid passages. The expandable mandrel is coupled to the support member and includes a third fluid passage. The tubular member is coupled to the mandrel and includes one or more sealing elements. The shoe is coupled to the tubular member and includes a fourth fluid passage. The at least one sealing member is adapted to prevent the entry of foreign material into an interior region of the tubular member.

According to another aspect of the present invention, a method of joining a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, is provided that includes positioning a mandrel within an interior region of the second tubular member. A portion of an interior region of the second tubular member is pressurized and the second tubular member is extruded off of the mandrel into engagement with the first tubular member.

According to another aspect of the present invention, a tubular liner is provided that includes an annular member having one or more sealing members at an end portion of the annular member, and one or more pressure relief passages at an end portion of the annular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a tubular liner and an annular body of a cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel.

According to another aspect of the present invention, a tie-back liner for lining an existing wellbore casing is provided that includes a tubular liner and an annular body of cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel. The annular body of a cured fluidic sealing material is coupled to the tubular liner.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, a

mandrel, a tubular member and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member. The mandrel includes a second fluid passage operably coupled to the first fluid passage, an interior portion, and an exterior portion. The interior portion of the mandrel is drillable.

- 5 The tubular member is coupled to the mandrel. The shoe is coupled to the tubular member. The shoe includes a third fluid passage operably coupled to the second fluid passage, an interior portion, and an exterior portion. The interior portion of the shoe is drillable.

- According to another aspect of the present invention, a wellhead is provided
10 that includes an outer casing and a plurality of concentric inner casings coupled to the outer casing. Each inner casing is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer casing.

- According to another aspect of the present invention, a wellhead is provided that include an outer casing at least partially positioned within a wellbore and a
15 plurality of substantially concentric inner casings coupled to the interior surface of the outer casing. One or more of the inner casings are coupled to the outer casing by expanding one or more of the inner casings into contact with at least a portion of the interior surface of the outer casing.

- According to another aspect of the present invention, a method of forming
20 a wellhead is provided that includes drilling a wellbore. An outer casing is positioned at least partially within an upper portion of the wellbore. A first tubular member is positioned within the outer casing. At least a portion of the first tubular member is expanded into contact with an interior surface of the outer casing. A second tubular member is positioned within the outer casing and the
25 first tubular member. At least a portion of the second tubular member is expanded into contact with an interior portion of the outer casing.

- According to another aspect of the present invention, an apparatus is provided that includes an outer tubular member, and a plurality of substantially concentric and overlapping inner tubular members coupled to the outer tubular
30 member. Each inner tubular member is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer inner tubular member.

According to another aspect of the present invention, an apparatus is provided that includes an outer tubular member, and a plurality of substantially concentric inner tubular members coupled to the interior surface of the outer tubular member by the process of expanding one or more of the inner tubular members into contact with at least a portion of the interior surface of the outer tubular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a first tubular member, and a second tubular member coupled to the first tubular member in an overlapping relationship. The inner diameter of the first tubular member is substantially equal to the inner diameter of the second tubular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a tubular member including at least one thin wall section and a thick wall section, and a compressible annular member coupled to each thin wall section.

According to another aspect of the present invention, a method of creating a casing in a borehole located in a subterranean formation is provided that includes supporting a tubular liner and a mandrel in the borehole using a support member. A fluidic material is injected into the borehole. An interior region of the mandrel is pressurized. A portion of the mandrel is displaced relative to the support member. The tubular liner is expanded.

According to another aspect of the present invention, a wellbore casing is provided that includes a first tubular member having a first inside diameter, and a second tubular member having a second inside diameter substantially equal to the first inside diameter coupled to the first tubular member in an overlapping relationship. The first and second tubular members are coupled by the process of deforming a portion of the second tubular member into contact with a portion of the first tubular member.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member including a fluid passage, a mandrel movably coupled to the support member including an expansion cone, at least one pressure chamber defined by and positioned between

the support member and mandrel fluidically coupled to the first fluid passage, and one or more releasable supports coupled to the support member adapted to support the tubular member.

According to another aspect of the present invention, an apparatus is
5 provided that includes one or more solid tubular members, each solid tubular member including one or more external seals, one or more slotted tubular members coupled to the solid tubular members, and a shoe coupled to one of the slotted tubular members.

According to another aspect of the present invention, a method of joining
10 a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member is provided that includes positioning a mandrel within an interior region of the second tubular member. A portion of the interior region of the mandrel is pressurized. The mandrel is displaced relative to the second tubular member. At
15 least a portion of the second tubular member is extruded off of the mandrel into engagement with the first tubular member.

According to another aspect of the present invention, an apparatus is provided that includes one or more primary solid tubulars, each primary solid tubular including one or more external annular seals, n slotted tubulars coupled
20 to the primary solid tubulars, n-1 intermediate solid tubulars coupled to and interleaved among the slotted tubulars, each intermediate solid tubular including one or more external annular seals, and a shoe coupled to one of the slotted tubulars.

According to another aspect of the present invention, a method of isolating
25 a first subterranean zone from a second subterranean zone in a wellbore is provided that includes positioning one or more primary solid tubulars within the wellbore, the primary solid tubulars traversing the first subterranean zone. One or more slotted tubulars are also positioned within the wellbore, the slotted tubulars traversing the second subterranean zone. The slotted tubulars and the
30 solid tubulars are fluidically coupled. The passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid and slotted tubulars is prevented.

According to another aspect of the present invention, a method of extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, is provided that includes positioning one or more primary solid tubulars within the wellbore. The primary solid tubulars with the casing are fluidically coupled. One or more slotted tubulars are positioned within the wellbore, the slotted tubulars traversing the producing subterranean zone. The slotted tubulars are fluidically coupled with the solid tubulars. The producing subterranean zone is fluidically isolated from at least one other subterranean zone within the wellbore. At least one of the slotted tubulars is fluidically isolated from the producing subterranean zone.

According to another aspect of the present invention, a method of creating a casing in a borehole while also drilling the borehole is also provided that includes installing a tubular liner, a mandrel, and a drilling assembly in the borehole. A fluidic material is injected within the tubular liner, mandrel and drilling assembly. At least a portion of the tubular liner is radially expanded while the borehole is drilled using the drilling assembly. In a preferred embodiment, the injecting includes injecting the fluidic material within an expandable chamber.

According to another aspect of the present invention, an apparatus is also provided that includes a support member, the support member including a first fluid passage; a mandrel coupled to the support member, the mandrel including: a second fluid passage; a tubular member coupled to the mandrel; and a shoe coupled to the tubular liner, the shoe including a third fluid passage; and a drilling assembly coupled to the shoe; wherein the first, second and third fluid passages and the drilling assembly are operably coupled.

According to another aspect of the present invention, a method of forming an underground pipeline within an underground tunnel including at least a first tubular member and a second tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, is also provided that includes positioning the first tubular member within the tunnel; positioning the second tubular member within the tunnel in an overlapping relationship with the first tubular member; positioning a mandrel and a drilling assembly within an interior region of the second tubular member;

injecting a fluidic material within the mandrel, drilling assembly and the second tubular member; extruding at least a portion of the second tubular member off of the mandrel into engagement with the first tubular member; and drilling the tunnel.

- 5 According to another aspect of the present invention, an apparatus is also provided that includes a wellbore, the wellbore formed by the process of drilling the wellbore; and a tubular liner positioned within the wellbore, the tubular liner formed by the process of extruding the tubular liner off of a mandrel while drilling the wellbore. In a preferred embodiment, the tubular liner is formed by the
10 process of: placing the tubular liner and mandrel within the wellbore; and pressurizing an interior portion of the tubular liner.

 According to another aspect of the present invention, a method of forming a wellbore casing in a wellbore is also provided that includes drilling out the wellbore while forming the wellbore casing.

- 15 According to another aspect of the present invention, a method of expanding a tubular member is provided that includes placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member.

- According to another aspect of the present invention, a method of coupling
20 a tubular member to preexisting structure is provided that includes positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member.

- 25 According to another aspect of the present invention, a method of repairing a defect in a preexisting structure using a tubular member is provided that includes positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the
30 mandrel with respect to the tubular member.

 According to another aspect of the present invention, an apparatus for radially expanding a tubular member is provided that includes a first tubular

member, a second tubular member positioned within the first tubular member, a third tubular member movably coupled to and positioned within the second tubular member, a first annular sealing member for sealing an interface between the first and second tubular members, a second annular sealing member for sealing
5 an interface between the second and third tubular members, and a mandrel positioned within the first tubular member and coupled to an end of the third tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a tubular member, a piston adapted to expand the diameter
10 of the tubular member positioned within the tubular member, and an annular chamber defined by the piston and tubular member. The piston includes a passage for conveying fluids out of the tubular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a first tubular member and a second tubular member
15 coupled to the first tubular member. The second tubular member is coupled to the first tubular member by the process of: positioning the second tubular member in an overlapping relationship to the first tubular member, placing a mandrel within the second tubular member, pressurizing an annular region within the second tubular member, and displacing the mandrel with respect to the second tubular
20 member.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure and a tubular member coupled to the preexisting structure. The tubular member is coupled to the preexisting structure by the process of: positioning the tubular member in an overlapping
25 relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure having a defective portion and a
30 tubular member coupled to the defective portion of the preexisting structure. The tubular member is coupled to the defective portion of the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to

the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, a method of expanding
5 a tubular member is provided that includes placing a mandrel within the tubular member, pressurizing a region within the tubular member; and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, a method of coupling
10 a tubular member to preexisting structure has been provided that includes positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, a method of repairing
15 a defect in a preexisting structure using a tubular member is provided that includes positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, an apparatus for
20 radially expanding a tubular member is provided that includes a first tubular member, a second tubular member coupled to the first tubular member, a third tubular member coupled to the second tubular member, and a mandrel positioned within the second tubular member and coupled to an end portion of the third
25 tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a tubular member, a piston adapted to expand the diameter of the tubular member positioned within the tubular member, the piston including a passage for conveying fluids out of the tubular member.

According to another aspect of the present invention, a wellbore casing is
30 provided that includes a first tubular member and a second tubular member coupled to the first tubular member. The second tubular member is coupled to the

first tubular member by the process of: positioning the second tubular member in an overlapping relationship to the first tubular member, placing a mandrel within the second tubular member, pressurizing an interior region within the second tubular member, and displacing the mandrel with respect to the second tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure and a tubular member coupled to the preexisting structure. The tubular member is coupled to the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the preexisting structure; placing a mandrel within the tubular member; pressurizing an interior region within the tubular member; and displacing the mandrel with respect to the tubular member.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure having a defective portion and a tubular member coupled to the defective portion of the preexisting structure. The tubular member is coupled to the defective portion of the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member.

According to another aspect of the invention, an apparatus is provided that includes a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more sealing members for sealing the interface between the first and second tubular members.

According to another aspect of the present invention, an apparatus is provided that includes a tubular assembly having a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more sealing members for sealing the interface between the first and second tubular members. The tubular assembly is formed by the process of radially expanding the tubular assembly.

According to another aspect of the present invention, an apparatus is provided that includes a tubular member and a mandrel positioned within the tubular member that includes a conical surface have an angle of attack ranging from about 10 to 30 degrees.

5 According to another aspect of the present invention, an expansion cone for expanding a tubular member is provided that includes a housing including a tapered first end and a second end, one or more grooves formed in the outer surface of the tapered first end, and one or more axial flow passages fluidly coupled to the circumferential grooves.

10 According to another aspect of the present invention, a method of lubricating the interface between a tubular member and an expansion cone having a first tapered end and a second end during the radial expansion of the tubular member by the expansion cone, wherein the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and
15 a trailing edge portion, is provided that includes injecting a lubricating fluid into the trailing edge portion.

 According to another aspect of the present invention, a method of removing debris formed during the radial expansion of a tubular member by an expansion cone from the interface between the tubular member and the expansion cone, the
20 expansion cone including a first tapered end and a second end, the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge portion, is provided that includes injecting a lubricating fluid into the interface between the tubular member and the expansion cone.

25 According to another aspect of the present invention, a tubular member is provided that includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member
30 for radial expansions of up to about 25%.

 According to another aspect of the present invention, a wellbore casing is provided that includes one or more tubular members. Each tubular member

includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of
5 up to about 25%.

According to another aspect of the present invention, a method of forming a wellbore casing is provided that includes placing a tubular member and an expansion cone in a wellbore and displacing the expansion cone relative to the tubular member. The tubular member includes an annular member having a wall
10 thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

According to another aspect of the present invention, a method of selecting
15 a group of tubular members for subsequent radial expansion is provided that includes radially expanding the ends of a representative sample of the group of tubular members, measuring the amount of necking of the walls of the radially expanded ends of the tubular members, and if the radially expanded ends of the tubular members do not exhibit necking for radial expansions of up to about 25%,
20 then accepting the group of tubular members.

According to another aspect of the present invention, a method of selecting a group of tubular members is provided that includes radially expanding the ends of a representative sample of the group of tubular members until each of the tubular members fail, and if the radially expanded ends of the tubular members
25 do not fail for radial expansions of up to about 30%, then accepting the group of tubular members.

According to another aspect of the present invention, a method of inserting a tubular member into a wellbore is provided that includes injecting a lubricating fluid into the wellbore and inserting the tubular member into the wellbore.

30 According to another aspect of the present invention, an expandable tubular member is provided that includes a first tubular section having a first outer diameter, an intermediate tubular section coupled to the first tubular section

having an intermediate outer diameter, and a second tubular section having a second outer diameter coupled to the intermediate tubular section having a second outer diameter. The first and second outer diameters are greater than the intermediate outer diameter.

5 According to another aspect of the present invention, a method of fabricating an expandable tubular member is provided that includes providing a tubular member having a first end, a second end, and an intermediate portion and radially expanding the first end and the second end of the tubular member.

10 According to another aspect of the present invention, an expansion cone for radially expanding a tubular member is provided that includes a first outer surface having a first angle of attack and a second outer surface coupled to the first outer surface having a second angle of attack. The first angle of attack is greater than the second angle of attack.

15 According to another aspect of the present invention, an apparatus is provided that includes a tubular member formed by the process of radially expanding an unexpanded tubular member into contact with an approximately cylindrical passage using an expansion cone. The unexpanded tubular member includes a first tubular section having a first outer diameter, an intermediate tubular section coupled to the first tubular section having an intermediate outer
20 diameter and a second tubular section having a second outer diameter coupled to the intermediate tubular section having a second outer diameter. The first and second outer diameters are greater than the intermediate outer diameter.

25 According to another aspect of the present invention, a method of joining a first tubular member to a second tubular member is provided that includes positioning at least a portion of the second tubular member within the first tubular member, radially expanding at least a portion of the second tubular member into contact with the first tubular member, and radially expanding the first and second tubular members. The interior diameter of the radially expanded second tubular member is substantially equal to the interior diameter of the radially unexpanded
30 portion of the first tubular member.

Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for creating a casing within the new section of the well borehole.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a first quantity of a fluidic material into the new section of the well borehole.

FIG. 3a is another fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a second quantity of a fluidic material into the new section of the well borehole.

FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of a portion of the cured hardenable fluidic sealing material from the new section of the well borehole.

FIG. 6 is a cross-sectional view of an embodiment of the overlapping joint between adjacent tubular members.

FIG. 7 is a fragmentary cross-sectional view of a preferred embodiment of the apparatus for creating a casing within a well borehole.

FIG. 8 is a fragmentary cross-sectional illustration of the placement of an expanded tubular member within another tubular member.

FIG. 9 is a cross-sectional illustration of a preferred embodiment of an apparatus for forming a casing including a drillable mandrel and shoe.

FIG. 9a is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9b is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9c is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 10a is a cross-sectional illustration of a wellbore including a pair of adjacent overlapping casings.

FIG. 10b is a cross-sectional illustration of an apparatus and method for creating a tie-back liner using an expandable tubular member.

FIG. 10c is a cross-sectional illustration of the pumping of a fluidic sealing material into the annular region between the tubular member and the existing casing.

FIG. 10d is a cross-sectional illustration of the pressurizing of the interior
5 of the tubular member below the mandrel.

FIG. 10e is a cross-sectional illustration of the extrusion of the tubular member off of the mandrel.

FIG. 10f is a cross-sectional illustration of the tie-back liner before drilling out the shoe and packer.

10 FIG. 10g is a cross-sectional illustration of the completed tie-back liner created using an expandable tubular member.

FIG. 11a is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 11b is a fragmentary cross-sectional view illustrating the placement of
15 an embodiment of an apparatus for hanging a tubular liner within the new section of the well borehole.

FIG. 11c is a fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

20 FIG. 11d is a fragmentary cross-sectional view illustrating the introduction of a wiper dart into the new section of the well borehole.

FIG. 11e is a fragmentary cross-sectional view illustrating the injection of a second quantity of a hardenable fluidic sealing material into the new section of the well borehole.

25 FIG. 11f is a fragmentary cross-sectional view illustrating the completion of the tubular liner.

FIG. 12 is a cross-sectional illustration of a preferred embodiment of a wellhead system utilizing expandable tubular members.

FIG. 13 is a partial cross-sectional illustration of a preferred embodiment
30 of the wellhead system of FIG. 12.

FIG. 14a is an illustration of the formation of an embodiment of a mono-diameter wellbore casing.

FIG. 14b is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14c is another illustration of the formation of the mono-diameter wellbore casing.

5 FIG. 14d is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14e is another illustration of the formation of the mono-diameter wellbore casing.

10 FIG. 14f is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 15 is an illustration of an embodiment of an apparatus for expanding a tubular member.

FIG. 15a is another illustration of the apparatus of FIG. 15.

FIG. 15b is another illustration of the apparatus of FIG. 15.

15 FIG. 16 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 17 is an illustration of an embodiment of an apparatus for expanding a tubular member.

FIG. 17a is another illustration of the apparatus of FIG. 16.

20 FIG. 17b is another illustration of the apparatus of FIG. 16.

FIG. 18 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 19 is an illustration of another embodiment of an apparatus for expanding a tubular member.

25 FIG. 19a is another illustration of the apparatus of FIG. 17.

FIG. 19b is another illustration of the apparatus of FIG. 17.

FIG. 20 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

30 FIG. 21 is an illustration of the isolation of subterranean zones using expandable tubulars.

FIG. 22a is a fragmentary cross-sectional illustration of an embodiment of an apparatus for forming a wellbore casing while drilling a wellbore.

FIG. 22b is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

FIG. 22c is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

5 FIG. 22d is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

FIG. 23a is a fragmentary cross-section illustration of an embodiment of an apparatus and method for expanding tubular members.

10 FIG. 23b is another fragmentary cross-sectional illustration of the apparatus of FIG. 23a.

FIG. 23c is another fragmentary cross-sectional illustration of the apparatus of FIG. 23a.

FIG. 24a is a fragmentary cross-section illustration of an embodiment of an apparatus and method for expanding tubular members.

15 FIG. 24b is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 24c is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

20 FIG. 24d is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 24e is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 25 is a partial cross-sectional illustration of an expansion mandrel expanding a tubular member.

25 FIG. 26 is a graphical illustration of the relationship between propagation pressure and the angle of attack of the expansion mandrel.

FIG. 27 is a cross-sectional illustration of an embodiment of an expandable connector.

30 FIG. 28 is a cross-sectional illustration of another embodiment of an expandable connector.

FIG. 29 is a cross-sectional illustration of another embodiment of an expandable connector.

FIG. 30 is a cross-sectional illustration of another embodiment of an expandable connector.

FIG. 31 is a fragmentary cross-sectional illustration of the lubrication of the interface between an expansion mandrel and a tubular member during the radial
5 expansion process.

FIG. 32 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 33 is an illustration of an embodiment of an expansion mandrel
10 including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 34 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 35 is an illustration of an embodiment of an expansion mandrel
15 including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 36 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel
20 and a tubular member during the radial expansion of the tubular member.

FIG. 37 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 38 is an illustration of an embodiment of an expansion mandrel
25 including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 39 is an illustration of a preferred embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular
30 member.

FIG. 40 is a cross-sectional illustration of the first axial groove of the expansion mandrel of FIG. 39.

FIG. 41 is a cross-sectional illustration of the circumferential groove of the expansion mandrel of FIG. 39.

FIG. 42 is a cross-sectional illustration of one of the second axial grooves of the expansion mandrel of FIG. 39.

5 FIG. 43 is a cross sectional illustration of an embodiment of an expansion mandrel including internal flow passages having inserts for adjusting the flow of lubricant fluids.

10 FIG. 44 is a cross sectional illustration of the expansion mandrel of FIG. 43 further including an insert having a filter for filtering out foreign materials from the lubricant fluids.

FIG. 45 is a cross sectional illustration of a preferred embodiment of an expandible tubular for use in forming and/or repairing a wellbore casing, pipeline, or foundation support.

15 FIG. 46 is a cross sectional illustration of the flared end of a tubular member selected for testing.

FIG. 47 is a cross sectional illustration of the flared end of a tubular member selected for testing that has structurally failed.

FIG. 48 is a cross sectional illustration of an embodiment of an expandable tubular member.

20 FIG. 49 is a flow chart illustration of an embodiment of a method for fabricating the expandable tubular member of FIG. 48.

FIG. 50a is a cross sectional illustration of a tubular member having upset end portions.

25 FIG. 50b is a cross sectional illustration of the tubular member of FIG. 50a after radial expansion of the upset end portions.

FIG. 50c is a cross sectional illustration of the tubular member of FIG. 50b further including expandable threaded connections provided in the expanded upset end portions.

30 FIG. 50d is a cross sectional illustration of tubular member of FIG. 50c, further including protective members provided on the outside diameter of the upset expanded portions of the tubular member.

FIG. 50e is a cross sectional illustration of the tubular member of FIG. 50d, further including a sealing member provided on the outside diameter of the intermediate unexpanded portion of the tubular member.

FIG. 51 is an illustration of an embodiment of an expansion cone optimally adapted to radially expand the tubular member of FIG. 48.

FIG. 52 is an illustration of another embodiment of an expansion cone optimally adapted to radially expand the tubular member of FIG. 48.

Fig. 53a is a fragmentary cross-sectional illustration of an embodiment of a wellbore casing formed using any one of the methods and apparatus for radially expanding a tubular member illustrated in Figs. 1-52.

Fig. 53b is a fragmentary cross-sectional illustration of an embodiment of a method and apparatus for further radially expanding the wellbore casing of Fig. 53a.

Fig. 53c. is a fragmentary cross-sectional illustration of the wellbore casing of Fig. 53b after further radial expansion.

Detailed Description of the Illustrative Embodiments

An apparatus and method for forming a wellbore casing within a subterranean formation is provided. The apparatus and method permits a wellbore casing to be formed in a subterranean formation by placing a tubular member and a mandrel in a new section of a wellbore, and then extruding the tubular member off of the mandrel by pressurizing an interior portion of the tubular member. The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and or gas passage. The apparatus and method further permits a new tubular member to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member. The apparatus and method further minimizes the reduction in the hole size of the wellbore casing necessitated by the addition of new sections of wellbore casing.

An apparatus and method for forming a tie-back liner using an expandable tubular member is also provided. The apparatus and method permits a tie-back liner to be created by extruding a tubular member off of a mandrel by pressurizing

and interior portion of the tubular member. In this manner, a tie-back liner is produced. The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and/or gas passage. The apparatus and method further permits a new tubular member
5 to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member.

An apparatus and method for expanding a tubular member is also provided that includes an expandable tubular member, mandrel and a shoe. In a preferred embodiment, the interior portions of the apparatus is composed of materials that
10 permit the interior portions to be removed using a conventional drilling apparatus. In this manner, in the event of a malfunction in a downhole region, the apparatus may be easily removed.

An apparatus and method for hanging an expandable tubular liner in a wellbore is also provided. The apparatus and method permit a tubular liner to be
15 attached to an existing section of casing. The apparatus and method further have application to the joining of tubular members in general.

An apparatus and method for forming a wellhead system is also provided. The apparatus and method permit a wellhead to be formed including a number of expandable tubular members positioned in a concentric arrangement. The
20 wellhead preferably includes an outer casing that supports a plurality of concentric casings using contact pressure between the inner casings and the outer casing. The resulting wellhead system eliminates many of the spools conventionally required, reduces the height of the Christmas tree facilitating servicing, lowers the load bearing areas of the wellhead resulting in a more stable system, and
25 eliminates costly and expensive hanger systems.

An apparatus and method for forming a mono-diameter well casing is also provided. The apparatus and method permit the creation of a well casing in a wellbore having a substantially constant internal diameter. In this manner, the operation of an oil or gas well is greatly simplified.

30 An apparatus and method for expanding tubular members is also provided. The apparatus and method utilize a piston-cylinder configuration in which a pressurized chamber is used to drive a mandrel to radially expand tubular

members. In this manner, higher operating pressures can be utilized. Throughout the radial expansion process, the tubular member is never placed in direct contact with the operating pressures. In this manner, damage to the tubular member is prevented while also permitting controlled radial expansion of the tubular member

5 in a wellbore.

An apparatus and method for forming a mono-diameter wellbore casing is also provided. The apparatus and method utilize a piston-cylinder configuration in which a pressurized chamber is used to drive a mandrel to radially expand tubular members. In this manner, higher operating pressures can be utilized.

10 Throughout the radial expansion process, the tubular member is never placed in direct contact with the operating pressures. In this manner, damage to the tubular member is prevented while also permitting controlled radial expansion of the tubular member in a wellbore.

An apparatus and method for isolating one or more subterranean zones

15 from one or more other subterranean zones is also provided. The apparatus and method permits a producing zone to be isolated from a nonproducing zone using a combination of solid and slotted tubulars. In the production mode, the teachings of the present disclosure may be used in combination with conventional, well known, production completion equipment and methods using a series of packers,

20 solid tubing, perforated tubing, and sliding sleeves, which will be inserted into the disclosed apparatus to permit the commingling and/or isolation of the subterranean zones from each other.

An apparatus and method for forming a wellbore casing while the wellbore is drilled is also provided. In this manner, a wellbore casing can be formed

25 simultaneous with the drilling out of a new section of the wellbore. In a preferred embodiment, the apparatus and method is used in combination with one or more of the apparatus and methods disclosed in the present disclosure for forming wellbore casings using expandable tubulars. Alternatively, the method and apparatus can be used to create a pipeline or tunnel in a time efficient manner.

30 An expandable connector is also provided. In a preferred implementation, the expandable connector is used in conjunction with one or more of the disclosed embodiments for expanding tubular members. In this manner, the expansion of

a plurality of tubular members coupled to one another using the expandable connector is optimized.

A lubrication and self-cleaning system for an expansion cone is also provided. In a preferred implementation, the expansion cone includes one or more
5 circumferential grooves and one or more axial grooves for providing a supply of lubricating fluid to the trailing edge portion of the interface between the expansion cone and a tubular member during the radial expansion process. In this manner, the frictional forces created during the radial expansion process are reduced which results in a reduction in the required operating pressures for radially expanding
10 the tubular member. Furthermore, the supply of lubricating fluid preferably removes loose material from tapered end of the expansion cone that is formed during the radial expansion process.

A method of testing and selecting tubular members for radial expansion operations is also provided. In a preferred embodiment, the method provides
15 tubular members that are optimally suited for radial expansion. In this manner, radially expanded tubular members having optimal structural properties are provided.

An expandable tubular member is provided that includes pre-expanded ends. In this manner, the subsequent radial expansion of the expandable tubular
20 member is optimized.

An expansion cone for expanding a tubular member is also provided that include a first outer surface having a first angle of attack and a second outer surface having a second angle of attack less than the first angle of attack. In this manner, the expansion of tubular members is optimally provided.

25 A two-step process for coupling a first tubular member to a second tubular member is also provided. During the first stage of the process, the first tubular member is preferably radially expanded into contact with the interior surface of the second tubular member. During the second stage of the process, both tubular members are radially expanded. The resulting assembly preferably provides a
30 substantially constant inside diameter.

In several alternative embodiments, the apparatus and methods are used to form and/or repair wellbore casings, pipelines, and/or structural supports.

Referring initially to Figs. 1-5, an embodiment of an apparatus and method for forming a wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes an existing cased section 110 having a
5 tubular casing 115 and an annular outer layer of cement 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new section 130.

As illustrated in Fig. 2, an apparatus 200 for forming a wellbore casing in
10 a subterranean formation is then positioned in the new section 130 of the wellbore 100. The apparatus 200 preferably includes an expandable mandrel or pig 205, a tubular member 210, a shoe 215, a lower cup seal 220, an upper cup seal 225, a fluid passage 230, a fluid passage 235, a fluid passage 240, seals 245, and a support member 250.

15 The expandable mandrel 205 is coupled to and supported by the support member 250. The expandable mandrel 205 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 205 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred
20 embodiment, the expandable mandrel 205 comprises a hydraulic expansion tool as disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member 210 is supported by the expandable mandrel 205. The
25 tubular member 210 is expanded in the radial direction and extruded off of the expandable mandrel 205. The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. In a preferred embodiment, the tubular member 210 is
30 fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 210 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred

embodiment, the inner and outer diameters of the tubular member 210 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 210 preferably comprises a solid member.

5 In a preferred embodiment, the end portion 260 of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 205 when it completes the extrusion of tubular member 210. In a preferred embodiment, the length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of
10 the tubular member 210 is preferably limited to between about 40 to 20,000 feet in length.

 The shoe 215 is coupled to the expandable mandrel 205 and the tubular member 210. The shoe 215 includes fluid passage 240. The shoe 215 may comprise any number of conventional commercially available shoes such as, for
15 example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 215 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down
20 plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and
plug after the completion of the cementing and expansion operations.

25 In a preferred embodiment, the shoe 215 includes one or more through and side outlet ports in fluidic communication with the fluid passage 240. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and tubular member 210. In a preferred embodiment, the shoe 215 includes the fluid passage 240 having an inlet geometry that can
30 receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

The lower cup seal 220 is coupled to and supported by the support member 250. The lower cup seal 220 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expandable mandrel 205. The lower cup seal 220 may comprise any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 220 comprises a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

10 The upper cup seal 225 is coupled to and supported by the support member 250. The upper cup seal 225 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 225 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the upper cup seal 225 comprises a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

The fluid passage 230 permits fluidic materials to be transported to and from the interior region of the tubular member 210 below the expandable mandrel 205. The fluid passage 230 is coupled to and positioned within the support member 250 and the expandable mandrel 205. The fluid passage 230 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 205. The fluid passage 230 is preferably positioned along a centerline of the apparatus 200.

25 The fluid passage 230 is preferably selected, in the casing running mode of operation, to transport materials such as drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore which could cause a loss of wellbore fluids and lead to hole collapse.

The fluid passage 235 permits fluidic materials to be released from the fluid passage 230. In this manner, during placement of the apparatus 200 within the

new section 130 of the wellbore 100, fluidic materials 255 forced up the fluid passage 230 can be released into the wellbore 100 above the tubular member 210 thereby minimizing surge pressures on the wellbore section 130. The fluid passage 235 is coupled to and positioned within the support member 250. The fluid
5 passage is further fluidically coupled to the fluid passage 230.

The fluid passage 235 preferably includes a control valve for controllably opening and closing the fluid passage 235. In a preferred embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The fluid passage 235 is preferably positioned substantially orthogonal to the centerline
10 of the apparatus 200.

The fluid passage 235 is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the
15 new wellbore section 130.

The fluid passage 240 permits fluidic materials to be transported to and from the region exterior to the tubular member 210 and shoe 215. The fluid passage 240 is coupled to and positioned within the shoe 215 in fluidic communication with the interior region of the tubular member 210 below the
20 expandable mandrel 205. The fluid passage 240 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage 240 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 210 below the expandable mandrel 205 can be fluidically isolated from the region exterior to the tubular member 210. This permits
25 the interior region of the tubular member 210 below the expandable mandrel 205 to be pressurized. The fluid passage 240 is preferably positioned substantially along the centerline of the apparatus 200.

The fluid passage 240 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0
30 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 210 and the new section 130 of the wellbore 100 with fluidic materials. In a preferred embodiment, the fluid passage 240

includes an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

The seals 245 are coupled to and supported by an end portion 260 of the
5 tubular member 210. The seals 245 are further positioned on an outer surface 265 of the end portion 260 of the tubular member 210. The seals 245 permit the overlapping joint between the end portion 270 of the casing 115 and the portion 260 of the tubular member 210 to be fluidically sealed. The seals 245 may comprise
10 any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 245 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 260 of the tubular member 210 and the end 270 of the existing casing 115.

15 In a preferred embodiment, the seals 245 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from the existing casing 115. In a preferred embodiment, the frictional force optimally provided by the seals 245 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 210.

20 The support member 250 is coupled to the expandable mandrel 205, tubular member 210, shoe 215, and seals 220 and 225. The support member 250 preferably comprises an annular member having sufficient strength to carry the apparatus 200 into the new section 130 of the wellbore 100. In a preferred embodiment, the support member 250 further includes one or more conventional
25 centralizers (not illustrated) to help stabilize the apparatus 200. In a preferred embodiment, the support member 250 comprises coiled tubing.

In a preferred embodiment, a quantity of lubricant 275 is provided in the annular region above the expandable mandrel 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off
30 of the expandable mandrel 205 is facilitated. The lubricant 275 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze

(3100). In a preferred embodiment, the lubricant 275 comprises Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

5 In a preferred embodiment, the support member 250 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

10 In a preferred embodiment, before or after positioning the apparatus 200 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion
15 process.

As illustrated in Fig. 3, the fluid passage 235 is then closed and a hardenable fluidic sealing material 305 is then pumped from a surface location into the fluid passage 230. The material 305 then passes from the fluid passage 230 into the interior region 310 of the tubular member 210 below the expandable mandrel 205.
20 The material 305 then passes from the interior region 310 into the fluid passage 240. The material 305 then exits the apparatus 200 and fills the annular region 315 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 315.

25 The material 305 is preferably pumped into the annular region 315 at pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being
30 pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 305 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 305 comprises a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is preferably determined using conventional empirical methods.

The annular region 315 preferably is filled with the material 305 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 315 of the new section 130 of the wellbore 100 will be filled with material 305.

In a particularly preferred embodiment, as illustrated in Fig. 3a, the wall thickness and/or the outer diameter of the tubular member 210 is reduced in the region adjacent to the mandrel 205 in order optimally permit placement of the apparatus 200 in positions in the wellbore with tight clearances. Furthermore, in this manner, the initiation of the radial expansion of the tubular member 210 during the extrusion process is optimally facilitated.

As illustrated in Fig. 4, once the annular region 315 has been adequately filled with material 305, a plug 405, or other similar device, is introduced into the fluid passage 240 thereby fluidically isolating the interior region 310 from the annular region 315. In a preferred embodiment, a non-hardenable fluidic material 306 is then pumped into the interior region 310 causing the interior region to pressurize. In this manner, the interior of the expanded tubular member 210 will not contain significant amounts of cured material 305. This reduces and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process. Once the interior region 310 becomes sufficiently pressurized, the tubular member 210 is extruded off of the expandable mandrel 205. During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210. In a preferred embodiment,

during the extrusion process, the mandrel 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In an alternative preferred embodiment, the extrusion process is commenced with the tubular member 210 positioned above the bottom of the new wellbore section 130, keeping the mandrel 205 stationary, and allowing the tubular member 210 to extrude off of the mandrel 205 and fall down the new wellbore section 130 under the force of gravity.

The plug 405 is preferably placed into the fluid passage 240 by introducing the plug 405 into the fluid passage 230 at a surface location in a conventional manner. The plug 405 preferably acts to fluidically isolate the hardenable fluidic sealing material 305 from the non hardenable fluidic material 306.

The plug 405 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the plug 405 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug 405 in the fluid passage 240, a non hardenable fluidic material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging, for example, from approximately 400 to 10,000 psi and 30 to 4,000 gallons/min. In this manner, the amount of hardenable fluidic sealing material within the interior 310 of the tubular member 210 is minimized. In a preferred embodiment, after placement of the plug 405 in the fluid passage 240, the non hardenable material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to maximize the extrusion speed.

In a preferred embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will depend upon the geometry of the expansion mandrel 205, the material composition of the tubular member 210 and expansion mandrel 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the

tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the mandrel 205.

5 For typical tubular members 210, the extrusion of the tubular member 210 off of the expandable mandrel will begin when the pressure of the interior region 310 reaches, for example, approximately 500 to 9,000 psi.

 During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for
10 example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expandable mandrel 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 2 ft/sec in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

15 When the end portion 260 of the tubular member 210 is extruded off of the expandable mandrel 205, the outer surface 265 of the end portion 260 of the tubular member 210 will preferably contact the interior surface 410 of the end portion 270 of the casing 115 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50
20 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to provide optimum pressure to activate the annular sealing members 245 and optimally provide resistance to axial motion to accommodate typical tensile and compressive loads.

 The overlapping joint between the section 410 of the existing casing 115 and
25 the section 265 of the expanded tubular member 210 preferably provides a gaseous and fluidic seal. In a particularly preferred embodiment, the sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint.

 In a preferred embodiment, the operating pressure and flow rate of the non hardenable fluidic material 306 is controllably ramped down when the expandable
30 mandrel 205 reaches the end portion 260 of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the

tubular member 210 off of the expandable mandrel 205 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 205 is within about 5 feet from completion of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 250 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may comprise, for example, any conventional commercially available shock absorber adapted for use in wellbore operations.

Alternatively, or in combination, a mandrel catching structure is provided in the end portion 260 of the tubular member 210 in order to catch or at least decelerate the mandrel 205.

Once the extrusion process is completed, the expandable mandrel 205 is removed from the wellbore 100. In a preferred embodiment, either before or after the removal of the expandable mandrel 205, the integrity of the fluidic seal of the overlapping joint between the upper portion 260 of the tubular member 210 and the lower portion 270 of the casing 115 is tested using conventional methods.

If the fluidic seal of the overlapping joint between the upper portion 260 of the tubular member 210 and the lower portion 270 of the casing 115 is satisfactory, then any uncured portion of the material 305 within the expanded tubular member 210 is then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The mandrel 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly 505 to drill out any hardened material 305 within the tubular member 210. The material 305 within the annular region 315 is then allowed to cure.

As illustrated in Fig. 5, preferably any remaining cured material 305 within the interior of the expanded tubular member 210 is then removed in a conventional manner using a conventional drill string 505. The resulting new section of casing 510 includes the expanded tubular member 210 and an outer annular layer 515 of cured material 305. The bottom portion of the apparatus 200

comprising the shoe 215 and dart 405 may then be removed by drilling out the shoe 215 and dart 405 using conventional drilling methods.

In a preferred embodiment, as illustrated in Fig. 6, the upper portion 260 of the tubular member 210 includes one or more sealing members 605 and one or
5 more pressure relief holes 610. In this manner, the overlapping joint between the lower portion 270 of the casing 115 and the upper portion 260 of the tubular member 210 is pressure-tight and the pressure on the interior and exterior surfaces of the tubular member 210 is equalized during the extrusion process.

In a preferred embodiment, the sealing members 605 are seated within
10 recesses 615 formed in the outer surface 265 of the upper portion 260 of the tubular member 210. In an alternative preferred embodiment, the sealing members 605 are bonded or molded onto the outer surface 265 of the upper portion 260 of the tubular member 210. The pressure relief holes 610 are preferably positioned in the last few feet of the tubular member 210. The pressure relief
15 holes reduce the operating pressures required to expand the upper portion 260 of the tubular member 210. This reduction in required operating pressure in turn reduces the velocity of the mandrel 205 upon the completion of the extrusion process. This reduction in velocity in turn minimizes the mechanical shock to the entire apparatus 200 upon the completion of the extrusion process.

Referring now to Fig. 7, a particularly preferred embodiment of an
20 apparatus 700 for forming a casing within a wellbore preferably includes an expandable mandrel or pig 705, an expandable mandrel or pig container 710, a tubular member 715, a float shoe 720, a lower cup seal 725, an upper cup seal 730, a fluid passage 735, a fluid passage 740, a support member 745, a body of lubricant
25 750, an overshot connection 755, another support member 760, and a stabilizer 765.

The expandable mandrel 705 is coupled to and supported by the support member 745. The expandable mandrel 705 is further coupled to the expandable mandrel container 710. The expandable mandrel 705 is preferably adapted to
30 controllably expand in a radial direction. The expandable mandrel 705 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred

embodiment, the expandable mandrel 705 comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

5 The expandable mandrel container 710 is coupled to and supported by the support member 745. The expandable mandrel container 710 is further coupled to the expandable mandrel 705. The expandable mandrel container 710 may be constructed from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods, stainless steel, titanium or
10 high strength steels. In a preferred embodiment, the expandable mandrel container 710 is fabricated from material having a greater strength than the material from which the tubular member 715 is fabricated. In this manner, the container 710 can be fabricated from a tubular material having a thinner wall thickness than the tubular member 210. This permits the container 710 to pass
15 through tight clearances thereby facilitating its placement within the wellbore.

In a preferred embodiment, once the expansion process begins, and the thicker, lower strength material of the tubular member 715 is expanded, the outside diameter of the tubular member 715 is greater than the outside diameter of the container 710.

20 The tubular member 715 is coupled to and supported by the expandable mandrel 705. The tubular member 715 is preferably expanded in the radial direction and extruded off of the expandable mandrel 705 substantially as described above with reference to Figs. 1-6. The tubular member 715 may be fabricated from any number of materials such as, for example, Oilfield Country
25 Tubular Goods (OCTG), automotive grade steel or plastics. In a preferred embodiment, the tubular member 715 is fabricated from OCTG.

In a preferred embodiment, the tubular member 715 has a substantially annular cross-section. In a particularly preferred embodiment, the tubular member 715 has a substantially circular annular cross-section.

30 The tubular member 715 preferably includes an upper section 805, an intermediate section 810, and a lower section 815. The upper section 805 of the tubular member 715 preferably is defined by the region beginning in the vicinity

of the mandrel container 710 and ending with the top section 820 of the tubular member 715. The intermediate section 810 of the tubular member 715 is preferably defined by the region beginning in the vicinity of the top of the mandrel container 710 and ending with the region in the vicinity of the mandrel 705. The lower section of the tubular member 715 is preferably defined by the region beginning in the vicinity of the mandrel 705 and ending at the bottom 825 of the tubular member 715.

In a preferred embodiment, the wall thickness of the upper section 805 of the tubular member 715 is greater than the wall thicknesses of the intermediate and lower sections 810 and 815 of the tubular member 715 in order to optimally facilitate the initiation of the extrusion process and optimally permit the apparatus 700 to be positioned in locations in the wellbore having tight clearances.

The outer diameter and wall thickness of the upper section 805 of the tubular member 715 may range, for example, from about 1.05 to 48 inches and 1/8 to 2 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the upper section 805 of the tubular member 715 range from about 3.5 to 16 inches and 3/8 to 1.5 inches, respectively.

The outer diameter and wall thickness of the intermediate section 810 of the tubular member 715 may range, for example, from about 2.5 to 50 inches and 1/16 to 1.5 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the intermediate section 810 of the tubular member 715 range from about 3.5 to 19 inches and 1/8 to 1.25 inches, respectively.

The outer diameter and wall thickness of the lower section 815 of the tubular member 715 may range, for example, from about 2.5 to 50 inches and 1/16 to 1.25 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the lower section 810 of the tubular member 715 range from about 3.5 to 19 inches and 1/8 to 1.25 inches, respectively. In a particularly preferred embodiment, the wall thickness of the lower section 815 of the tubular member 715 is further increased to increase the strength of the shoe 720 when drillable materials such as, for example, aluminum are used.

The tubular member 715 preferably comprises a solid tubular member. In a preferred embodiment, the end portion 820 of the tubular member 715 is slotted,

perforated, or otherwise modified to catch or slow down the mandrel 705 when it completes the extrusion of tubular member 715. In a preferred embodiment, the length of the tubular member 715 is limited to minimize the possibility of buckling. For typical tubular member 715 materials, the length of the tubular member 715 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 720 is coupled to the expandable mandrel 705 and the tubular member 715. The shoe 720 includes the fluid passage 740. In a preferred embodiment, the shoe 720 further includes an inlet passage 830, and one or more jet ports 835. In a particularly preferred embodiment, the cross-sectional shape of the inlet passage 830 is adapted to receive a latch-down dart, or other similar elements, for blocking the inlet passage 830. The interior of the shoe 720 preferably includes a body of solid material 840 for increasing the strength of the shoe 720. In a particularly preferred embodiment, the body of solid material 840 comprises aluminum.

The shoe 720 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II Down-Jet float shoe, or guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 720 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimize guiding the tubular member 715 in the wellbore, optimize the seal between the tubular member 715 and an existing wellbore casing, and to optimally facilitate the removal of the shoe 720 by drilling it out after completion of the extrusion process.

The lower cup seal 725 is coupled to and supported by the support member 745. The lower cup seal 725 prevents foreign materials from entering the interior region of the tubular member 715 above the expandable mandrel 705. The lower cup seal 725 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 725 comprises a SIP cup, available from

Halliburton Energy Services in Dallas, TX in order to optimally provide a debris barrier and hold a body of lubricant.

The upper cup seal 730 is coupled to and supported by the support member 760. The upper cup seal 730 prevents foreign materials from entering the interior
5 region of the tubular member 715. The upper cup seal 730 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cup modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the upper cup seal 730 comprises a SIP cup available from Halliburton Energy Services in Dallas, TX
10 in order to optimally provide a debris barrier and contain a body of lubricant.

The fluid passage 735 permits fluidic materials to be transported to and from the interior region of the tubular member 715 below the expandable mandrel 705. The fluid passage 735 is fluidically coupled to the fluid passage 740. The fluid passage 735 is preferably coupled to and positioned within the support member
15 760, the support member 745, the mandrel container 710, and the expandable mandrel 705. The fluid passage 735 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 705. The fluid passage 735 is preferably positioned along a centerline of the apparatus 700. The fluid passage 735 is preferably selected to transport materials such as cement, drilling mud or
20 epoxies at flow rates and pressures ranging from about 40 to 3,000 gallons/minute and 500 to 9,000 psi in order to optimally provide sufficient operating pressures to extrude the tubular member 715 off of the expandable mandrel 705.

As described above with reference to Figs. 1-6, during placement of the apparatus 700 within a new section of a wellbore, fluidic materials forced up the
25 fluid passage 735 can be released into the wellbore above the tubular member 715. In a preferred embodiment, the apparatus 700 further includes a pressure release passage that is coupled to and positioned within the support member 260. The pressure release passage is further fluidically coupled to the fluid passage 735. The pressure release passage preferably includes a control valve for controllably
30 opening and closing the fluid passage. In a preferred embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The pressure release passage is preferably positioned substantially orthogonal to the

centerline of the apparatus 700. The pressure release passage is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 500 gallons/minute and 0 to 1,000 psi in order to reduce the drag on the apparatus 700 during insertion into a new section
5 of a wellbore and to minimize surge pressures on the new wellbore section.

The fluid passage 740 permits fluidic materials to be transported to and from the region exterior to the tubular member 715. The fluid passage 740 is preferably coupled to and positioned within the shoe 720 in fluidic communication with the interior region of the tubular member 715 below the expandable mandrel
10 705. The fluid passage 740 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in the inlet 830 of the fluid passage 740 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 715 below the expandable mandrel 705 can be optimally fluidically isolated from the region exterior to the tubular member 715.
15 This permits the interior region of the tubular member 715 below the expandable mandrel 205 to be pressurized.

The fluid passage 740 is preferably positioned substantially along the centerline of the apparatus 700. The fluid passage 740 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and
20 pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill an annular region between the tubular member 715 and a new section of a wellbore with fluidic materials. In a preferred embodiment, the fluid passage 740 includes an inlet passage 830 having a geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be
25 sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

In a preferred embodiment, the apparatus 700 further includes one or more seals 845 coupled to and supported by the end portion 820 of the tubular member 715. The seals 845 are further positioned on an outer surface of the end portion
30 820 of the tubular member 715. The seals 845 permit the overlapping joint between an end portion of preexisting casing and the end portion 820 of the tubular member 715 to be fluidically sealed. The seals 845 may comprise any

number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 845 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in
5 Dallas, TX in order to optimally provide a hydraulic seal and a load bearing interference fit in the overlapping joint between the tubular member 715 and an existing casing with optimal load bearing capacity to support the tubular member 715.

In a preferred embodiment, the seals 845 are selected to provide a sufficient
10 frictional force to support the expanded tubular member 715 from the existing casing. In a preferred embodiment, the frictional force provided by the seals 845 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 715.

The support member 745 is preferably coupled to the expandable mandrel
15 705 and the overshot connection 755. The support member 745 preferably comprises an annular member having sufficient strength to carry the apparatus 700 into a new section of a wellbore. The support member 745 may comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubular modified in
20 accordance with the teachings of the present disclosure. In a preferred embodiment, the support member 745 comprises conventional drill pipe available from various steel mills in the United States.

In a preferred embodiment, a body of lubricant 750 is provided in the annular region above the expandable mandrel container 710 within the interior of
25 the tubular member 715. In this manner, the extrusion of the tubular member 715 off of the expandable mandrel 705 is facilitated. The lubricant 705 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants, or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 750 comprises
30 Climax 1500 Antisieze (3100) available from Halliburton Energy Services in Houston, TX in order to optimally provide lubrication to facilitate the extrusion process.

The overshot connection 755 is coupled to the support member 745 and the support member 760. The overshot connection 755 preferably permits the support member 745 to be removably coupled to the support member 760. The overshot connection 755 may comprise any number of conventional commercially available
5 overshot connections such as, for example, Innerstring Sealing Adapter, Innerstring Flat-Face Sealing Adapter or EZ Drill Setting Tool Stinger. In a preferred embodiment, the overshot connection 755 comprises a Innerstring Adapter with an Upper Guide available from Halliburton Energy Services in Dallas, TX.

10 The support member 760 is preferably coupled to the overshot connection 755 and a surface support structure (not illustrated). The support member 760 preferably comprises an annular member having sufficient strength to carry the apparatus 700 into a new section of a wellbore. The support member 760 may
15 comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubulars modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the support member 760 comprises a conventional drill pipe available from steel mills in the United States.

The stabilizer 765 is preferably coupled to the support member 760. The
20 stabilizer 765 also preferably stabilizes the components of the apparatus 700 within the tubular member 715. The stabilizer 765 preferably comprises a spherical member having an outside diameter that is about 80 to 99% of the interior diameter of the tubular member 715 in order to optimally minimize buckling of the tubular member 715. The stabilizer 765 may comprise any number
25 of conventional commercially available stabilizers such as, for example, EZ Drill Star Guides, packer shoes or drag blocks modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the stabilizer 765 comprises a sealing adapter upper guide available from Halliburton Energy Services in Dallas, TX.

30 In a preferred embodiment, the support members 745 and 760 are thoroughly cleaned prior to assembly to the remaining portions of the apparatus 700. In this manner, the introduction of foreign material into the apparatus 700

is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 700.

In a preferred embodiment, before or after positioning the apparatus 700 within a new section of a wellbore, a couple of wellbore volumes are circulated
5 through the various flow passages of the apparatus 700 in order to ensure that no foreign materials are located within the wellbore that might clog up the various flow passages and valves of the apparatus 700 and to ensure that no foreign material interferes with the expansion mandrel 705 during the expansion process.

In a preferred embodiment, the apparatus 700 is operated substantially as
10 described above with reference to Figs. 1-7 to form a new section of casing within a wellbore.

As illustrated in Fig. 8, in an alternative preferred embodiment, the method and apparatus described herein is used to repair an existing wellbore casing 805 by forming a tubular liner 810 inside of the existing wellbore casing 805. In a
15 preferred embodiment, an outer annular lining of cement is not provided in the repaired section. In the alternative preferred embodiment, any number of fluidic materials can be used to expand the tubular liner 810 into intimate contact with the damaged section of the wellbore casing such as, for example, cement, epoxy, slag mix, or drilling mud. In the alternative preferred embodiment, sealing
20 members 815 are preferably provided at both ends of the tubular member in order to optimally provide a fluidic seal. In an alternative preferred embodiment, the tubular liner 810 is formed within a horizontally positioned pipeline section, such as those used to transport hydrocarbons or water, with the tubular liner 810 placed in an overlapping relationship with the adjacent pipeline section. In this manner,
25 underground pipelines can be repaired without having to dig out and replace the damaged sections.

In another alternative preferred embodiment, the method and apparatus described herein is used to directly line a wellbore with a tubular liner 810. In a preferred embodiment, an outer annular lining of cement is not provided between
30 the tubular liner 810 and the wellbore. In the alternative preferred embodiment, any number of fluidic materials can be used to expand the tubular liner 810 into

intimate contact with the wellbore such as, for example, cement, epoxy, slag mix, or drilling mud.

Referring now to Figs. 9, 9a, 9b and 9c, a preferred embodiment of an apparatus 900 for forming a wellbore casing includes an expandable tubular member 902, a support member 904, an expandable mandrel or pig 906, and a shoe 908. In a preferred embodiment, the design and construction of the mandrel 906 and shoe 908 permits easy removal of those elements by drilling them out. In this manner, the assembly 900 can be easily removed from a wellbore using a conventional drilling apparatus and corresponding drilling methods.

The expandable tubular member 902 preferably includes an upper portion 910, an intermediate portion 912 and a lower portion 914. During operation of the apparatus 900, the tubular member 902 is preferably extruded off of the mandrel 906 by pressurizing an interior region 966 of the tubular member 902. The tubular member 902 preferably has a substantially annular cross-section.

In a particularly preferred embodiment, an expandable tubular member 915 is coupled to the upper portion 910 of the expandable tubular member 902. During operation of the apparatus 900, the tubular member 915 is preferably extruded off of the mandrel 906 by pressurizing the interior region 966 of the tubular member 902. The tubular member 915 preferably has a substantially annular cross-section.

In a preferred embodiment, the wall thickness of the tubular member 915 is greater than the wall thickness of the tubular member 902.

The tubular member 915 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steels, titanium or stainless steels. In a preferred embodiment, the tubular member 915 is fabricated from oilfield tubulars in order to optimally provide approximately the same mechanical properties as the tubular member 902. In a particularly preferred embodiment, the tubular member 915 has a plastic yield point ranging from about 40,000 to 135,000 psi in order to optimally provide approximately the same yield properties as the tubular member 902. The tubular member 915 may comprise a plurality of tubular members coupled end to end.

In a preferred embodiment, the upper end portion of the tubular member 915 includes one or more sealing members for optimally providing a fluidic and/or gaseous seal with an existing section of wellbore casing.

In a preferred embodiment, the combined length of the tubular members 902 and 915 are limited to minimize the possibility of buckling. For typical tubular member materials, the combined length of the tubular members 902 and 915 are limited to between about 40 to 20,000 feet in length.

The lower portion 914 of the tubular member 902 is preferably coupled to the shoe 908 by a threaded connection 968. The intermediate portion 912 of the tubular member 902 preferably is placed in intimate sliding contact with the mandrel 906.

The tubular member 902 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steels, titanium or stainless steels. In a preferred embodiment, the tubular member 902 is fabricated from oilfield tubulars in order to optimally provide approximately the same mechanical properties as the tubular member 915. In a particularly preferred embodiment, the tubular member 902 has a plastic yield point ranging from about 40,000 to 135,000 psi in order to optimally provide approximately the same yield properties as the tubular member 915.

The wall thickness of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 may range, for example, from about 1/16 to 1.5 inches. In a preferred embodiment, the wall thickness of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 range from about 1/8 to 1.25 in order to optimally provide wall thickness that are about the same as the tubular member 915. In a preferred embodiment, the wall thickness of the lower portion 914 is less than or equal to the wall thickness of the upper portion 910 in order to optimally provide a geometry that will fit into tight clearances downhole.

The outer diameter of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 may range, for example, from about 1.05 to 48 inches. In a preferred embodiment, the outer diameter of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 range from about

3 ½ to 19 inches in order to optimally provide the ability to expand the most commonly used oilfield tubulars.

The length of the tubular member 902 is preferably limited to between about 2 to 5 feet in order to optimally provide enough length to contain the
5 mandrel 906 and a body of lubricant.

The tubular member 902 may comprise any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the tubular member 902 comprises Oilfield Country Tubular Goods available from various U.S. steel mills.
10 The tubular member 915 may comprise any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the tubular member 915 comprises Oilfield Country Tubular Goods available from various U.S. steel mills.

The various elements of the tubular member 902 may be coupled using any
15 number of conventional process such as, for example, threaded connections, welding or machined from one piece. In a preferred embodiment, the various elements of the tubular member 902 are coupled using welding. The tubular member 902 may comprise a plurality of tubular elements that are coupled end to end. The various elements of the tubular member 915 may be coupled using any
20 number of conventional process such as, for example, threaded connections, welding or machined from one piece. In a preferred embodiment, the various elements of the tubular member 915 are coupled using welding. The tubular member 915 may comprise a plurality of tubular elements that are coupled end to end. The tubular members 902 and 915 may be coupled using any number of
25 conventional process such as, for example, threaded connections, welding or machined from one piece.

The support member 904 preferably includes an innerstring adapter 916, a fluid passage 918, an upper guide 920, and a coupling 922. During operation of the apparatus 900, the support member 904 preferably supports the apparatus 900
30 during movement of the apparatus 900 within a wellbore. The support member 904 preferably has a substantially annular cross-section.

The support member 904 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel, coiled tubing or stainless steel. In a preferred embodiment, the support member 904 is fabricated from low alloy steel in order
5 to optimally provide high yield strength.

The innerstring adaptor 916 preferably is coupled to and supported by a conventional drill string support from a surface location. The innerstring adaptor 916 may be coupled to a conventional drill string support 971 by a threaded connection 970.

10 The fluid passage 918 is preferably used to convey fluids and other materials to and from the apparatus 900. In a preferred embodiment, the fluid passage 918 is fluidly coupled to the fluid passage 952. In a preferred embodiment, the fluid passage 918 is used to convey hardenable fluidic sealing materials to and from the apparatus 900. In a particularly preferred embodiment, the fluid passage 918 may
15 include one or more pressure relief passages (not illustrated) to release fluid pressure during positioning of the apparatus 900 within a wellbore. In a preferred embodiment, the fluid passage 918 is positioned along a longitudinal centerline of the apparatus 900. In a preferred embodiment, the fluid passage 918 is selected to permit the conveyance of hardenable fluidic materials at operating pressures
20 ranging from about 0 to 9,000 psi.

The upper guide 920 is coupled to an upper portion of the support member 904. The upper guide 920 preferably is adapted to center the support member 904 within the tubular member 915. The upper guide 920 may comprise any number of conventional guide members modified in accordance with the teachings of the
25 present disclosure. In a preferred embodiment, the upper guide 920 comprises an innerstring adapter available from Halliburton Energy Services in Dallas, TX order to optimally guide the apparatus 900 within the tubular member 915.

The coupling 922 couples the support member 904 to the mandrel 906. The coupling 922 preferably comprises a conventional threaded connection.

30 The various elements of the support member 904 may be coupled using any number of conventional processes such as, for example, welding, threaded

connections or machined from one piece. In a preferred embodiment, the various elements of the support member 904 are coupled using threaded connections.

The mandrel 906 preferably includes a retainer 924, a rubber cup 926, an expansion cone 928, a lower cone retainer 930, a body of cement 932, a lower guide
5 934, an extension sleeve 936, a spacer 938, a housing 940, a sealing sleeve 942, an upper cone retainer 944, a lubricator mandrel 946, a lubricator sleeve 948, a guide 950, and a fluid passage 952.

The retainer 924 is coupled to the lubricator mandrel 946, lubricator sleeve
10 948, and the rubber cup 926. The retainer 924 couples the rubber cup 926 to the lubricator sleeve 948. The retainer 924 preferably has a substantially annular cross-section. The retainer 924 may comprise any number of conventional commercially available retainers such as, for example, slotted spring pins or roll pin.

The rubber cup 926 is coupled to the retainer 924, the lubricator mandrel
15 946, and the lubricator sleeve 948. The rubber cup 926 prevents the entry of foreign materials into the interior region 972 of the tubular member 902 below the rubber cup 926. The rubber cup 926 may comprise any number of conventional commercially available rubber cups such as, for example, TP cups or Selective Injection Packer (SIP) cup. In a preferred embodiment, the rubber cup 926
20 comprises a SIP cup available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign materials.

In a particularly preferred embodiment, a body of lubricant is further provided in the interior region 972 of the tubular member 902 in order to lubricate the interface between the exterior surface of the mandrel 902 and the interior
25 surface of the tubular members 902 and 915. The lubricant may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antiseize (3100). In a preferred embodiment, the lubricant comprises Climax 1500 Antiseize (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in
30 order to optimally provide lubrication to facilitate the extrusion process.

The expansion cone 928 is coupled to the lower cone retainer 930, the body of cement 932, the lower guide 934, the extension sleeve 936, the housing 940, and

the upper cone retainer 944. In a preferred embodiment, during operation of the apparatus 900, the tubular members 902 and 915 are extruded off of the outer surface of the expansion cone 928. In a preferred embodiment, axial movement of the expansion cone 928 is prevented by the lower cone retainer 930, housing 940
5 and the upper cone retainer 944. Inner radial movement of the expansion cone 928 is prevented by the body of cement 932, the housing 940, and the upper cone retainer 944.

The expansion cone 928 preferably has a substantially annular cross section. The outside diameter of the expansion cone 928 is preferably tapered to provide
10 a cone shape. The wall thickness of the expansion cone 928 may range, for example, from about 0.125 to 3 inches. In a preferred embodiment, the wall thickness of the expansion cone 928 ranges from about 0.25 to 0.75 inches in order to optimally provide adequate compressive strength with minimal material. The maximum and minimum outside diameters of the expansion cone 928 may range,
15 for example, from about 1 to 47 inches. In a preferred embodiment, the maximum and minimum outside diameters of the expansion cone 928 range from about 3.5 to 19 in order to optimally provide expansion of generally available oilfield tubulars

The expansion cone 928 may be fabricated from any number of conventional commercially available materials such as, for example, ceramic, tool steel, titanium
20 or low alloy steel. In a preferred embodiment, the expansion cone 928 is fabricated from tool steel in order to optimally provide high strength and abrasion resistance. The surface hardness of the outer surface of the expansion cone 928 may range, for example, from about 50 Rockwell C to 70 Rockwell C. In a preferred embodiment, the surface hardness of the outer surface of the expansion cone 928 ranges from
25 about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In a preferred embodiment, the expansion cone 928 is heat treated to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness.

The lower cone retainer 930 is coupled to the expansion cone 928 and the
30 housing 940. In a preferred embodiment, axial movement of the expansion cone 928 is prevented by the lower cone retainer 930. Preferably, the lower cone retainer 930 has a substantially annular cross-section.

The lower cone retainer 930 may be fabricated from any number of conventional commercially available materials such as, for example, ceramic, tool steel, titanium or low alloy steel. In a preferred embodiment, the lower cone retainer 930 is fabricated from tool steel in order to optimally provide high strength and abrasion resistance. The surface hardness of the outer surface of the lower cone retainer 930 may range, for example, from about 50 Rockwell C to 70 Rockwell C. In a preferred embodiment, the surface hardness of the outer surface of the lower cone retainer 930 ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In a preferred embodiment, the lower cone retainer 930 is heat treated to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness.

In a preferred embodiment, the lower cone retainer 930 and the expansion cone 928 are formed as an integral one-piece element in order to reduce the number of components and increase the overall strength of the apparatus. The outer surface of the lower cone retainer 930 preferably mates with the inner surfaces of the tubular members 902 and 915.

The body of cement 932 is positioned within the interior of the mandrel 906. The body of cement 932 provides an inner bearing structure for the mandrel 906. The body of cement 932 further may be easily drilled out using a conventional drill device. In this manner, the mandrel 906 may be easily removed using a conventional drilling device.

The body of cement 932 may comprise any number of conventional commercially available cement compounds. Alternatively, aluminum, cast iron or some other drillable metallic, composite, or aggregate material may be substituted for cement. The body of cement 932 preferably has a substantially annular cross-section.

The lower guide 934 is coupled to the extension sleeve 936 and housing 940. During operation of the apparatus 900, the lower guide 934 preferably helps guide the movement of the mandrel 906 within the tubular member 902. The lower guide 934 preferably has a substantially annular cross-section.

The lower guide 934 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In a preferred embodiment, the lower guide 934 is fabricated from low alloy steel in order to optimally provide high yield strength.

- 5 The outer surface of the lower guide 934 preferably mates with the inner surface of the tubular member 902 to provide a sliding fit.

The extension sleeve 936 is coupled to the lower guide 934 and the housing 940. During operation of the apparatus 900, the extension sleeve 936 preferably helps guide the movement of the mandrel 906 within the tubular member 902.

- 10 The extension sleeve 936 preferably has a substantially annular cross-section.

The extension sleeve 936 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In a preferred embodiment, the extension sleeve 936 is fabricated from low alloy steel in order to optimally provide high yield strength. The outer surface of the extension sleeve 936 preferably mates with the inner surface of the tubular member 902 to provide a sliding fit. In a preferred embodiment, the extension sleeve 936 and the lower guide 934 are formed as an integral one-piece element in order to minimize the number of components and increase the strength of the apparatus.

- 20 The spacer 938 is coupled to the sealing sleeve 942. The spacer 938 preferably includes the fluid passage 952 and is adapted to mate with the extension tube 960 of the shoe 908. In this manner, a plug or dart can be conveyed from the surface through the fluid passages 918 and 952 into the fluid passage 962. Preferably, the spacer 938 has a substantially annular cross-section.

- 25 The spacer 938 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the spacer 938 is fabricated from aluminum in order to optimally provide drillability. The end of the spacer 938 preferably mates with the end of the extension tube 960. In a preferred embodiment, the spacer 30 938 and the sealing sleeve 942 are formed as an integral one-piece element in order to reduce the number of components and increase the strength of the apparatus.

The housing 940 is coupled to the lower guide 934, extension sleeve 936, expansion cone 928, body of cement 932, and lower cone retainer 930. During operation of the apparatus 900, the housing 940 preferably prevents inner radial motion of the expansion cone 928. Preferably, the housing 940 has a substantially
5 annular cross-section.

The housing 940 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In a preferred embodiment, the housing 940 is fabricated from low alloy steel in order to optimally provide high yield strength. In a
10 preferred embodiment, the lower guide 934, extension sleeve 936 and housing 940 are formed as an integral one-piece element in order to minimize the number of components and increase the strength of the apparatus.

In a particularly preferred embodiment, the interior surface of the housing 940 includes one or more protrusions to facilitate the connection between the
15 housing 940 and the body of cement 932.

The sealing sleeve 942 is coupled to the support member 904, the body of cement 932, the spacer 938, and the upper cone retainer 944. During operation of the apparatus, the sealing sleeve 942 preferably provides support for the mandrel 906. The sealing sleeve 942 is preferably coupled to the support member 904 using
20 the coupling 922. Preferably, the sealing sleeve 942 has a substantially annular cross-section.

The sealing sleeve 942 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the sealing sleeve 942 is fabricated from
25 aluminum in order to optimally provide drillability of the sealing sleeve 942.

In a particularly preferred embodiment, the outer surface of the sealing sleeve 942 includes one or more protrusions to facilitate the connection between the sealing sleeve 942 and the body of cement 932.

In a particularly preferred embodiment, the spacer 938 and the sealing
30 sleeve 942 are integrally formed as a one-piece element in order to minimize the number of components.

The upper cone retainer 944 is coupled to the expansion cone 928, the sealing sleeve 942, and the body of cement 932. During operation of the apparatus 900, the upper cone retainer 944 preferably prevents axial motion of the expansion cone 928. Preferably, the upper cone retainer 944 has a substantially annular cross-section.

The upper cone retainer 944 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the upper cone retainer 944 is fabricated from aluminum in order to optimally provide drillability of the upper cone retainer 944.

In a particularly preferred embodiment, the upper cone retainer 944 has a cross-sectional shape designed to provide increased rigidity. In a particularly preferred embodiment, the upper cone retainer 944 has a cross-sectional shape that is substantially I-shaped to provide increased rigidity and minimize the amount of material that would have to be drilled out.

The lubricator mandrel 946 is coupled to the retainer 924, the rubber cup 926, the upper cone retainer 944, the lubricator sleeve 948, and the guide 950. During operation of the apparatus 900, the lubricator mandrel 946 preferably contains the body of lubricant in the annular region 972 for lubricating the interface between the mandrel 906 and the tubular member 902. Preferably, the lubricator mandrel 946 has a substantially annular cross-section.

The lubricator mandrel 946 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the lubricator mandrel 946 is fabricated from aluminum in order to optimally provide drillability of the lubricator mandrel 946.

The lubricator sleeve 948 is coupled to the lubricator mandrel 946, the retainer 924, the rubber cup 926, the upper cone retainer 944, the lubricator sleeve 948, and the guide 950. During operation of the apparatus 900, the lubricator sleeve 948 preferably supports the rubber cup 926. Preferably, the lubricator sleeve 948 has a substantially annular cross-section.

The lubricator sleeve 948 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the lubricator sleeve 948 is fabricated from aluminum in order to optimally provide drillability of the
5 lubricator sleeve 948.

As illustrated in Fig. 9c, the lubricator sleeve 948 is supported by the lubricator mandrel 946. The lubricator sleeve 948 in turn supports the rubber cup 926. The retainer 924 couples the rubber cup 926 to the lubricator sleeve 948. In a preferred embodiment, seals 949a and 949b are provided between the lubricator
10 mandrel 946, lubricator sleeve 948, and rubber cup 926 in order to optimally seal off the interior region 972 of the tubular member 902.

The guide 950 is coupled to the lubricator mandrel 946, the retainer 924, and the lubricator sleeve 948. During operation of the apparatus 900, the guide 950 preferably guides the apparatus on the support member 904. Preferably, the
15 guide 950 has a substantially annular cross-section.

The guide 950 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the guide 950 is fabricated from aluminum order to optimally provide drillability of the guide 950.

20 The fluid passage 952 is coupled to the mandrel 906. During operation of the apparatus, the fluid passage 952 preferably conveys hardenable fluidic materials. In a preferred embodiment, the fluid passage 952 is positioned about the centerline of the apparatus 900. In a particularly preferred embodiment, the fluid passage 952 is adapted to convey hardenable fluidic materials at pressures
25 and flow rate ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/min in order to optimally provide pressures and flow rates to displace and circulate fluids during the installation of the apparatus 900.

The various elements of the mandrel 906 may be coupled using any number of conventional process such as, for example, threaded connections, welded
30 connections or cementing. In a preferred embodiment, the various elements of the mandrel 906 are coupled using threaded connections and cementing.

The shoe 908 preferably includes a housing 954, a body of cement 956, a sealing sleeve 958, an extension tube 960, a fluid passage 962, and one or more outlet jets 964.

The housing 954 is coupled to the body of cement 956 and the lower portion
5 914 of the tubular member 902. During operation of the apparatus 900, the housing 954 preferably couples the lower portion of the tubular member 902 to the shoe 908 to facilitate the extrusion and positioning of the tubular member 902. Preferably, the housing 954 has a substantially annular cross-section.

The housing 954 may be fabricated from any number of conventional
10 commercially available materials such as, for example, steel or aluminum. In a preferred embodiment, the housing 954 is fabricated from aluminum in order to optimally provide drillability of the housing 954.

In a particularly preferred embodiment, the interior surface of the housing
954 includes one or more protrusions to facilitate the connection between the body
15 of cement 956 and the housing 954.

The body of cement 956 is coupled to the housing 954, and the sealing sleeve
958. In a preferred embodiment, the composition of the body of cement 956 is selected to permit the body of cement to be easily drilled out using conventional drilling machines and processes.

The composition of the body of cement 956 may include any number of
20 conventional cement compositions. In an alternative embodiment, a drillable material such as, for example, aluminum or iron may be substituted for the body of cement 956.

The sealing sleeve 958 is coupled to the body of cement 956, the extension
25 tube 960, the fluid passage 962, and one or more outlet jets 964. During operation of the apparatus 900, the sealing sleeve 958 preferably is adapted to convey a hardenable fluidic material from the fluid passage 952 into the fluid passage 962 and then into the outlet jets 964 in order to inject the hardenable fluidic material into an annular region external to the tubular member 902. In a preferred
30 embodiment, during operation of the apparatus 900, the sealing sleeve 958 further includes an inlet geometry that permits a conventional plug or dart 974 to become lodged in the inlet of the sealing sleeve 958. In this manner, the fluid passage 962

may be blocked thereby fluidically isolating the interior region 966 of the tubular member 902.

In a preferred embodiment, the sealing sleeve 958 has a substantially annular cross-section. The sealing sleeve 958 may be fabricated from any number of conventional commercially available materials such as, for example, steel,
5 aluminum or cast iron. In a preferred embodiment, the sealing sleeve 958 is fabricated from aluminum in order to optimally provide drillability of the sealing sleeve 958.

The extension tube 960 is coupled to the sealing sleeve 958, the fluid
10 passage 962, and one or more outlet jets 964. During operation of the apparatus 900, the extension tube 960 preferably is adapted to convey a hardenable fluidic material from the fluid passage 952 into the fluid passage 962 and then into the outlet jets 964 in order to inject the hardenable fluidic material into an annular region external to the tubular member 902. In a preferred embodiment, during
15 operation of the apparatus 900, the sealing sleeve 960 further includes an inlet geometry that permits a conventional plug or dart 974 to become lodged in the inlet of the sealing sleeve 958. In this manner, the fluid passage 962 is blocked thereby fluidically isolating the interior region 966 of the tubular member 902. In a preferred embodiment, one end of the extension tube 960 mates with one end of
20 the spacer 938 in order to optimally facilitate the transfer of material between the two.

In a preferred embodiment, the extension tube 960 has a substantially annular cross-section. The extension tube 960 may be fabricated from any number of conventional commercially available materials such as, for example, steel,
25 aluminum or cast iron. In a preferred embodiment, the extension tube 960 is fabricated from aluminum in order to optimally provide drillability of the extension tube 960.

The fluid passage 962 is coupled to the sealing sleeve 958, the extension tube 960, and one or more outlet jets 964. During operation of the apparatus 900,
30 the fluid passage 962 is preferably conveys hardenable fluidic materials. In a preferred embodiment, the fluid passage 962 is positioned about the centerline of the apparatus 900. In a particularly preferred embodiment, the fluid passage 962

is adapted to convey hardenable fluidic materials at pressures and flow rate ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/min in order to optimally provide fluids at operationally efficient rates.

The outlet jets 964 are coupled to the sealing sleeve 958, the extension tube
5 960, and the fluid passage 962. During operation of the apparatus 900, the outlet jets 964 preferably convey hardenable fluidic material from the fluid passage 962 to the region exterior of the apparatus 900. In a preferred embodiment, the shoe 908 includes a plurality of outlet jets 964.

In a preferred embodiment, the outlet jets 964 comprise passages drilled in
10 the housing 954 and the body of cement 956 in order to simplify the construction of the apparatus 900.

The various elements of the shoe 908 may be coupled using any number of conventional process such as, for example, threaded connections, cement or machined from one piece of material. In a preferred embodiment, the various
15 elements of the shoe 908 are coupled using cement.

In a preferred embodiment, the assembly 900 is operated substantially as described above with reference to Figs. 1-8 to create a new section of casing in a wellbore or to repair a wellbore casing or pipeline.

In particular, in order to extend a wellbore into a subterranean formation,
20 a drill string is used in a well known manner to drill out material from the subterranean formation to form a new section.

The apparatus 900 for forming a wellbore casing in a subterranean formation is then positioned in the new section of the wellbore. In a particularly preferred embodiment, the apparatus 900 includes the tubular member 915. In a
25 preferred embodiment, a hardenable fluidic sealing hardenable fluidic sealing material is then pumped from a surface location into the fluid passage 918. The hardenable fluidic sealing material then passes from the fluid passage 918 into the interior region 966 of the tubular member 902 below the mandrel 906. The hardenable fluidic sealing material then passes from the interior region 966 into
30 the fluid passage 962. The hardenable fluidic sealing material then exits the apparatus 900 via the outlet jets 964 and fills an annular region between the exterior of the tubular member 902 and the interior wall of the new section of the

wellbore. Continued pumping of the hardenable fluidic sealing material causes the material to fill up at least a portion of the annular region.

The hardenable fluidic sealing material is preferably pumped into the annular region at pressures and flow rates ranging, for example, from about 0 to 5,000 psi and 0 to 1,500 gallons/min, respectively. In a preferred embodiment, the hardenable fluidic sealing material is pumped into the annular region at pressures and flow rates that are designed for the specific wellbore section in order to optimize the displacement of the hardenable fluidic sealing material while not creating high enough circulating pressures such that circulation might be lost and that could cause the wellbore to collapse. The optimum pressures and flow rates are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material comprises blended cements designed specifically for the well section being lined available from Halliburton Energy Services in Dallas, TX in order to optimally provide support for the new tubular member while also maintaining optimal flow characteristics so as to minimize operational difficulties during the displacement of the cement in the annular region. The optimum composition of the blended cements is preferably determined using conventional empirical methods.

The annular region preferably is filled with the hardenable fluidic sealing material in sufficient quantities to ensure that, upon radial expansion of the tubular member 902, the annular region of the new section of the wellbore will be filled with hardenable material.

Once the annular region has been adequately filled with hardenable fluidic sealing material, a plug or dart 974, or other similar device, preferably is introduced into the fluid passage 962 thereby fluidically isolating the interior region 966 of the tubular member 902 from the external annular region. In a preferred embodiment, a non hardenable fluidic material is then pumped into the interior region 966 causing the interior region 966 to pressurize. In a particularly preferred embodiment, the plug or dart 974, or other similar device, preferably is

introduced into the fluid passage 962 by introducing the plug or dart 974, or other similar device into the non hardenable fluidic material. In this manner, the amount of cured material within the interior of the tubular members 902 and 915 is minimized.

5 Once the interior region 966 becomes sufficiently pressurized, the tubular members 902 and 915 are extruded off of the mandrel 906. The mandrel 906 may be fixed or it may be expandable. During the extrusion process, the mandrel 906 is raised out of the expanded portions of the tubular members 902 and 915 using the support member 904. During this extrusion process, the shoe 908 is preferably
10 substantially stationary.

The plug or dart 974 is preferably placed into the fluid passage 962 by introducing the plug or dart 974 into the fluid passage 918 at a surface location in a conventional manner. The plug or dart 974 may comprise any number of conventional commercially available devices for plugging a fluid passage such as,
15 for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the plug or dart 974 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug or dart 974 in the fluid passage 962, the non
20 hardenable fluidic material is preferably pumped into the interior region 966 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to optimally extrude the tubular members 902 and 915 off of the mandrel 906.

For typical tubular members 902 and 915, the extrusion of the tubular
25 members 902 and 915 off of the expandable mandrel will begin when the pressure of the interior region 966 reaches approximately 500 to 9,000 psi. In a preferred embodiment, the extrusion of the tubular members 902 and 915 off of the mandrel 906 begins when the pressure of the interior region 966 reaches approximately 1,200 to 8,500 psi with a flow rate of about 40 to 1250 gallons/minute.

30 During the extrusion process, the mandrel 906 may be raised out of the expanded portions of the tubular members 902 and 915 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion

process, the mandrel 906 is raised out of the expanded portions of the tubular members 902 and 915 at rates ranging from about 0 to 2 ft/sec in order to optimally provide pulling speed fast enough to permit efficient operation and permit full expansion of the tubular members 902 and 915 prior to curing of the
5 hardenable fluidic sealing material; but not so fast that timely adjustment of operating parameters during operation is prevented.

When the upper end portion of the tubular member 915 is extruded off of the mandrel 906, the outer surface of the upper end portion of the tubular member 915 will preferably contact the interior surface of the lower end portion of the
10 existing casing to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint between the upper end of the tubular member 915 and the existing section of wellbore casing ranges from approximately 400 to 10,000 psi in order to optimally provide contact
15 pressure to activate the sealing members and provide optimal resistance such that the tubular member 915 and existing wellbore casing will carry typical tensile and compressive loads.

In a preferred embodiment, the operating pressure and flow rate of the non hardenable fluidic material will be controllably ramped down when the mandrel
20 906 reaches the upper end portion of the tubular member 915. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 915 off of the expandable mandrel 906 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when
25 the mandrel 906 has completed approximately all but about the last 5 feet of the extrusion process.

In an alternative preferred embodiment, the operating pressure and/or flow rate of the hardenable fluidic sealing material and/or the non hardenable fluidic material are controlled during all phases of the operation of the apparatus 900 to
30 minimize shock.

Alternatively, or in combination, a shock absorber is provided in the support member 904 in order to absorb the shock caused by the sudden release of pressure.

Alternatively, or in combination, a mandrel catching structure is provided above the support member 904 in order to catch or at least decelerate the mandrel 906.

Once the extrusion process is completed, the mandrel 906 is removed from the wellbore. In a preferred embodiment, either before or after the removal of the mandrel 906, the integrity of the fluidic seal of the overlapping joint between the upper portion of the tubular member 915 and the lower portion of the existing casing is tested using conventional methods. If the fluidic seal of the overlapping joint between the upper portion of the tubular member 915 and the lower portion of the existing casing is satisfactory, then the uncured portion of any of the hardenable fluidic sealing material within the expanded tubular member 915 is then removed in a conventional manner. The hardenable fluidic sealing material within the annular region between the expanded tubular member 915 and the existing casing and new section of wellbore is then allowed to cure.

Preferably any remaining cured hardenable fluidic sealing material within the interior of the expanded tubular members 902 and 915 is then removed in a conventional manner using a conventional drill string. The resulting new section of casing preferably includes the expanded tubular members 902 and 915 and an outer annular layer of cured hardenable fluidic sealing material. The bottom portion of the apparatus 900 comprising the shoe 908 may then be removed by drilling out the shoe 908 using conventional drilling methods.

In an alternative embodiment, during the extrusion process, it may be necessary to remove the entire apparatus 900 from the interior of the wellbore due to a malfunction. In this circumstance, a conventional drill string is used to drill out the interior sections of the apparatus 900 in order to facilitate the removal of the remaining sections. In a preferred embodiment, the interior elements of the apparatus 900 are fabricated from materials such as, for example, cement and aluminum, that permit a conventional drill string to be employed to drill out the interior components.

In particular, in a preferred embodiment, the composition of the interior sections of the mandrel 906 and shoe 908, including one or more of the body of cement 932, the spacer 938, the sealing sleeve 942, the upper cone retainer 944,

the lubricator mandrel 946, the lubricator sleeve 948, the guide 950, the housing 954, the body of cement 956, the sealing sleeve 958, and the extension tube 960, are selected to permit at least some of these components to be drilled out using conventional drilling methods and apparatus. In this manner, in the event of a malfunction downhole, the apparatus 900 may be easily removed from the wellbore.

Referring now to Figs. 10a, 10b, 10c, 10d, 10e, 10f, and 10g a method and apparatus for creating a tie-back liner in a wellbore will now be described. As illustrated in Fig. 10a, a wellbore 1000 positioned in a subterranean formation 1002 includes a first casing 1004 and a second casing 1006.

The first casing 1004 preferably includes a tubular liner 1008 and a cement annulus 1010. The second casing 1006 preferably includes a tubular liner 1012 and a cement annulus 1014. In a preferred embodiment, the second casing 1006 is formed by expanding a tubular member substantially as described above with reference to Figs. 1-9c or below with reference to Figs. 11a-11f.

In a particularly preferred embodiment, an upper portion of the tubular liner 1012 overlaps with a lower portion of the tubular liner 1008. In a particularly preferred embodiment, an outer surface of the upper portion of the tubular liner 1012 includes one or more sealing members 1016 for providing a fluidic seal between the tubular liners 1008 and 1012.

Referring to Fig. 10b, in order to create a tie-back liner that extends from the overlap between the first and second casings, 1004 and 1006, an apparatus 1100 is preferably provided that includes an expandable mandrel or pig 1105, a tubular member 1110, a shoe 1115, one or more cup seals 1120, a fluid passage 1130, a fluid passage 1135, one or more fluid passages 1140, seals 1145, and a support member 1150.

The expandable mandrel or pig 1105 is coupled to and supported by the support member 1150. The expandable mandrel 1105 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 1105 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the expandable mandrel 1105 comprises a hydraulic expansion tool

substantially as disclosed in U.S. Pat. No. 5,348,095, the disclosure of which is incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member 1110 is coupled to and supported by the expandable
5 mandrel 1105. The tubular member 1105 is expanded in the radial direction and extruded off of the expandable mandrel 1105. The tubular member 1110 may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods, 13 chromium tubing or plastic piping. In a preferred embodiment, the tubular member 1110 is fabricated from Oilfield Country Tubular Goods.

10 The inner and outer diameters of the tubular member 1110 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the inner and outer diameters of the tubular member 1110 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide coverage for typical oilfield casing sizes. The tubular member
15 1110 preferably comprises a solid member.

In a preferred embodiment, the upper end portion of the tubular member 1110 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 1105 when it completes the extrusion of tubular member 1110. In a preferred embodiment, the length of the tubular member 1110 is limited to
20 minimize the possibility of buckling. For typical tubular member 1110 materials, the length of the tubular member 1110 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 1115 is coupled to the expandable mandrel 1105 and the tubular member 1110. The shoe 1115 includes the fluid passage 1135. The shoe 1115 may
25 comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 1115 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down
30 plug with side ports radiating off of the exit flow port available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 1100 to the

overlap between the tubular member 1100 and the casing 1012, optimally fluidically isolate the interior of the tubular member 1100 after the latch down plug has seated, and optimally permit drilling out of the shoe 1115 after completion of the expansion and cementing operations.

5 In a preferred embodiment, the shoe 1115 includes one or more side outlet ports 1140 in fluidic communication with the fluid passage 1135. In this manner, the shoe 1115 injects hardenable fluidic sealing material into the region outside the shoe 1115 and tubular member 1110. In a preferred embodiment, the shoe 1115 includes one or more of the fluid passages 1140 each having an inlet geometry that
10 can receive a dart and/or a ball sealing member. In this manner, the fluid passages 1140 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1130.

The cup seal 1120 is coupled to and supported by the support member 1150. The cup seal 1120 prevents foreign materials from entering the interior region of
15 the tubular member 1110 adjacent to the expandable mandrel 1105. The cup seal 1120 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the cup seal 1120 comprises a SIP cup, available from Halliburton
20 Energy Services in Dallas, TX in order to optimally provide a barrier to debris and contain a body of lubricant.

The fluid passage 1130 permits fluidic materials to be transported to and from the interior region of the tubular member 1110 below the expandable mandrel 1105. The fluid passage 1130 is coupled to and positioned within the
25 support member 1150 and the expandable mandrel 1105. The fluid passage 1130 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 1105. The fluid passage 1130 is preferably positioned along a centerline of the apparatus 1100. The fluid passage 1130 is preferably selected to transport materials such as cement, drilling mud or epoxies at flow rates and
30 pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally provide sufficient operating pressures to circulate fluids at operationally efficient rates.

The fluid passage 1135 permits fluidic materials to be transmitted from fluid passage 1130 to the interior of the tubular member 1110 below the mandrel 1105.

The fluid passages 1140 permits fluidic materials to be transported to and from the region exterior to the tubular member 1110 and shoe 1115. The fluid passages 1140 are coupled to and positioned within the shoe 1115 in fluidic communication with the interior region of the tubular member 1110 below the expandable mandrel 1105. The fluid passages 1140 preferably have a cross-sectional shape that permits a plug, or other similar device, to be placed in the fluid passages 1140 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 1110 below the expandable mandrel 1105 can be fluidically isolated from the region exterior to the tubular member 1105. This permits the interior region of the tubular member 1110 below the expandable mandrel 1105 to be pressurized.

The fluid passages 1140 are preferably positioned along the periphery of the shoe 1115. The fluid passages 1140 are preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 1110 and the tubular liner 1008 with fluidic materials. In a preferred embodiment, the fluid passages 1140 include an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passages 1140 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1130. In a preferred embodiment, the apparatus 1100 includes a plurality of fluid passage 1140.

In an alternative embodiment, the base of the shoe 1115 includes a single inlet passage coupled to the fluid passages 1140 that is adapted to receive a plug, or other similar device, to permit the interior region of the tubular member 1110 to be fluidically isolated from the exterior of the tubular member 1110.

The seals 1145 are coupled to and supported by a lower end portion of the tubular member 1110. The seals 1145 are further positioned on an outer surface of the lower end portion of the tubular member 1110. The seals 1145 permit the overlapping joint between the upper end portion of the casing 1012 and the lower end portion of the tubular member 1110 to be fluidically sealed.

The seals 1145 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 1145 comprise seals molded from Stratalock epoxy available
5 from Halliburton Energy Services in Dallas, TX in order to optimally provide a hydraulic seal in the overlapping joint and optimally provide load carrying capacity to withstand the range of typical tensile and compressive loads.

In a preferred embodiment, the seals 1145 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 1110 from the
10 tubular liner 1008. In a preferred embodiment, the frictional force provided by the seals 1145 ranges from about 1,000 to 1,000,000 lbf in tension and compression in order to optimally support the expanded tubular member 1110.

The support member 1150 is coupled to the expandable mandrel 1105, tubular member 1110, shoe 1115, and seal 1120. The support member 1150
15 preferably comprises an annular member having sufficient strength to carry the apparatus 1100 into the wellbore 1000. In a preferred embodiment, the support member 1150 further includes one or more conventional centralizers (not illustrated) to help stabilize the tubular member 1110.

In a preferred embodiment, a quantity of lubricant 1150 is provided in the
20 annular region above the expandable mandrel 1105 within the interior of the tubular member 1110. In this manner, the extrusion of the tubular member 1110 off of the expandable mandrel 1105 is facilitated. The lubricant 1150 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants or Climax 1500 Antiseize (3100).
25 In a preferred embodiment, the lubricant 1150 comprises Climax 1500 Antiseize (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide lubrication for the extrusion process.

In a preferred embodiment, the support member 1150 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 1100. In this
30 manner, the introduction of foreign material into the apparatus 1100 is minimized. This minimizes the possibility of foreign material clogging the various flow

passages and valves of the apparatus 1100 and to ensure that no foreign material interferes with the expansion mandrel 1105 during the extrusion process.

In a particularly preferred embodiment, the apparatus 1100 includes a packer 1155 coupled to the bottom section of the shoe 1115 for fluidically isolating the region of the wellbore 1000 below the apparatus 1100. In this manner, fluidic materials are prevented from entering the region of the wellbore 1000 below the apparatus 1100. The packer 1155 may comprise any number of conventional commercially available packers such as, for example, EZ Drill Packer, EZ SV Packer or a drillable cement retainer. In a preferred embodiment, the packer 1155 comprises an EZ Drill Packer available from Halliburton Energy Services in Dallas, TX. In an alternative embodiment, a high gel strength pill may be set below the tie-back in place of the packer 1155. In another alternative embodiment, the packer 1155 may be omitted.

In a preferred embodiment, before or after positioning the apparatus 1100 within the wellbore 1100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 1000 that might clog up the various flow passages and valves of the apparatus 1100 and to ensure that no foreign material interferes with the operation of the expansion mandrel 1105.

As illustrated in Fig. 10c, a hardenable fluidic sealing material 1160 is then pumped from a surface location into the fluid passage 1130. The material 1160 then passes from the fluid passage 1130 into the interior region of the tubular member 1110 below the expandable mandrel 1105. The material 1160 then passes from the interior region of the tubular member 1110 into the fluid passages 1140. The material 1160 then exits the apparatus 1100 and fills the annular region between the exterior of the tubular member 1110 and the interior wall of the tubular liner 1008. Continued pumping of the material 1160 causes the material 1160 to fill up at least a portion of the annular region.

The material 1160 may be pumped into the annular region at pressures and flow rates ranging, for example, from about 0 to 5,000 psi and 0 to 1,500 gallons/min, respectively. In a preferred embodiment, the material 1160 is pumped into the annular region at pressures and flow rates specifically designed for the

casing sizes being run, the annular spaces being filled, the pumping equipment available, and the properties of the fluid being pumped. The optimum flow rates and pressures are preferably calculated using conventional empirical methods.

The hardenable fluidic sealing material 1160 may comprise any number of
5 conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 1160 comprises blended cements specifically designed for well section being tied-back, available from Halliburton Energy
10 Services in Dallas, TX in order to optimally provide proper support for the tubular member 1110 while maintaining optimum flow characteristics so as to minimize operational difficulties during the displacement of cement in the annular region. The optimum blend of the blended cements are preferably determined using conventional empirical methods.

The annular region may be filled with the material 1160 in sufficient
15 quantities to ensure that, upon radial expansion of the tubular member 1110, the annular region will be filled with material 1160.

As illustrated in Fig. 10d, once the annular region has been adequately filled with material 1160, one or more plugs 1165, or other similar devices, preferably are introduced into the fluid passages 1140 thereby fluidically isolating the interior
20 region of the tubular member 1110 from the annular region external to the tubular member 1110. In a preferred embodiment, a non hardenable fluidic material 1161 is then pumped into the interior region of the tubular member 1110 below the mandrel 1105 causing the interior region to pressurize. In a particularly preferred embodiment, the one or more plugs 1165, or other similar devices, are introduced
25 into the fluid passage 1140 with the introduction of the non hardenable fluidic material. In this manner, the amount of hardenable fluidic material within the interior of the tubular member 1110 is minimized.

As illustrated in Fig. 10e, once the interior region becomes sufficiently pressurized, the tubular member 1110 is extruded off of the expandable mandrel
30 1105. During the extrusion process, the expandable mandrel 1105 is raised out of the expanded portion of the tubular member 1110.

The plugs 1165 are preferably placed into the fluid passages 1140 by introducing the plugs 1165 into the fluid passage 1130 at a surface location in a conventional manner. The plugs 1165 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example,
5 brass balls, plugs, rubber balls, or darts modified in accordance with the teachings of the present disclosure.

In a preferred embodiment, the plugs 1165 comprise low density rubber balls. In an alternative embodiment, for a shoe 1105 having a common central inlet passage, the plugs 1165 comprise a single latch down dart.

10 After placement of the plugs 1165 in the fluid passages 1140, the non hardenable fluidic material 1161 is preferably pumped into the interior region of the tubular member 1110 below the mandrel 1105 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min.

In a preferred embodiment, after placement of the plugs 1165 in the fluid passages
15 1140, the non hardenable fluidic material 1161 is preferably pumped into the interior region of the tubular member 1110 below the mandrel 1105 at pressures and flow rates ranging from approximately 1200 to 8500 psi and 40 to 1250 gallons/min in order to optimally provide extrusion of typical tubulars.

For typical tubular members 1110, the extrusion of the tubular member
20 1110 off of the expandable mandrel 1105 will begin when the pressure of the interior region of the tubular member 1110 below the mandrel 1105 reaches, for example, approximately 1200 to 8500 psi. In a preferred embodiment, the extrusion of the tubular member 1110 off of the expandable mandrel 1105 begins when the pressure of the interior region of the tubular member 1110 below the
25 mandrel 1105 reaches approximately 1200 to 8500 psi.

During the extrusion process, the expandable mandrel 1105 may be raised out of the expanded portion of the tubular member 1110 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expandable mandrel 1105 is raised out of the expanded portion of the
30 tubular member 1110 at rates ranging from about 0 to 2 ft/sec in order to optimally provide permit adjustment of operational parameters, and optimally ensure that the extrusion process will be completed before the material 1160 cures.

In a preferred embodiment, at least a portion 1180 of the tubular member 1110 has an internal diameter less than the outside diameter of the mandrel 1105. In this manner, when the mandrel 1105 expands the section 1180 of the tubular member 1110, at least a portion of the expanded section 1180 effects a seal with
5 at least the wellbore casing 1012. In a particularly preferred embodiment, the seal is effected by compressing the seals 1016 between the expanded section 1180 and the wellbore casing 1012. In a preferred embodiment, the contact pressure of the joint between the expanded section 1180 of the tubular member 1110 and the casing 1012 ranges from about 500 to 10,000 psi in order to optimally provide
10 pressure to activate the sealing members 1145 and provide optimal resistance to ensure that the joint will withstand typical extremes of tensile and compressive loads.

In an alternative preferred embodiment, substantially all of the entire length of the tubular member 1110 has an internal diameter less than the outside
15 diameter of the mandrel 1105. In this manner, extrusion of the tubular member 1110 by the mandrel 1105 results in contact between substantially all of the expanded tubular member 1110 and the existing casing 1008. In a preferred embodiment, the contact pressure of the joint between the expanded tubular member 1110 and the casings 1008 and 1012 ranges from about 500 to 10,000 psi
20 in order to optimally provide pressure to activate the sealing members 1145 and provide optimal resistance to ensure that the joint will withstand typical extremes of tensile and compressive loads.

In a preferred embodiment, the operating pressure and flow rate of the material 1161 is controllably ramped down when the expandable mandrel 1105
25 reaches the upper end portion of the tubular member 1110. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 1110 off of the expandable mandrel 1105 can be minimized. In a preferred embodiment, the operating pressure of the fluidic material 1161 is reduced in a substantially linear fashion from 100% to about 10% during the end
30 of the extrusion process beginning when the mandrel 1105 has completed approximately all but about 5 feet of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 1150 in order to absorb the shock caused by the sudden release of pressure.

Alternatively, or in combination, a mandrel catching structure is provided
5 in the upper end portion of the tubular member 1110 in order to catch or at least decelerate the mandrel 1105.

Referring to Fig. 10f, once the extrusion process is completed, the expandable mandrel 1105 is removed from the wellbore 1000. In a preferred embodiment, either before or after the removal of the expandable mandrel 1105,
10 the integrity of the fluidic seal of the joint between the upper portion of the tubular member 1110 and the upper portion of the tubular liner 1108 is tested using conventional methods. If the fluidic seal of the joint between the upper portion of the tubular member 1110 and the upper portion of the tubular liner 1008 is satisfactory, then the uncured portion of the material 1160 within the
15 expanded tubular member 1110 is then removed in a conventional manner. The material 1160 within the annular region between the tubular member 1110 and the tubular liner 1008 is then allowed to cure.

As illustrated in Fig. 10f, preferably any remaining cured material 1160 within the interior of the expanded tubular member 1110 is then removed in a
20 conventional manner using a conventional drill string. The resulting tie-back liner of casing 1170 includes the expanded tubular member 1110 and an outer annular layer 1175 of cured material 1160.

As illustrated in Fig. 10g, the remaining bottom portion of the apparatus 1100 comprising the shoe 1115 and packer 1155 is then preferably removed by
25 drilling out the shoe 1115 and packer 1155 using conventional drilling methods.

In a particularly preferred embodiment, the apparatus 1100 incorporates the apparatus 900.

Referring now to Figs. 11a-11f, an embodiment of an apparatus and method for hanging a tubular liner off of an existing wellbore casing will now be described.
30 As illustrated in Fig. 11a, a wellbore 1200 is positioned in a subterranean formation 1205. The wellbore 1200 includes an existing cased section 1210 having a tubular casing 1215 and an annular outer layer of cement 1220.

In order to extend the wellbore 1200 into the subterranean formation 1205, a drill string 1225 is used in a well known manner to drill out material from the subterranean formation 1205 to form a new section 1230.

As illustrated in Fig. 11b, an apparatus 1300 for forming a wellbore casing in a subterranean formation is then positioned in the new section 1230 of the wellbore 100. The apparatus 1300 preferably includes an expandable mandrel or pig 1305, a tubular member 1310, a shoe 1315, a fluid passage 1320, a fluid passage 1330, a fluid passage 1335, seals 1340, a support member 1345, and a wiper plug 1350.

The expandable mandrel 1305 is coupled to and supported by the support member 1345. The expandable mandrel 1305 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 1305 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the expandable mandrel 1305 comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the disclosure of which is incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member 1310 is coupled to and supported by the expandable mandrel 1305. The tubular member 1310 is preferably expanded in the radial direction and extruded off of the expandable mandrel 1305. The tubular member 1310 may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing or plastic casing. In a preferred embodiment, the tubular member 1310 is fabricated from OCTG. The inner and outer diameters of the tubular member 1310 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the inner and outer diameters of the tubular member 1310 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly encountered wellbore sizes.

In a preferred embodiment, the tubular member 1310 includes an upper portion 1355, an intermediate portion 1360, and a lower portion 1365. In a

preferred embodiment, the wall thickness and outer diameter of the upper portion 1355 of the tubular member 1310 range from about 3/8 to 1 1/2 inches and 3 1/2 to 16 inches, respectively. In a preferred embodiment, the wall thickness and outer diameter of the intermediate portion 1360 of the tubular member 1310 range from about 0.625 to 0.75 inches and 3 to 19 inches, respectively. In a preferred embodiment, the wall thickness and outer diameter of the lower portion 1365 of the tubular member 1310 range from about 3/8 to 1.5 inches and 3.5 to 16 inches, respectively.

In a particularly preferred embodiment, the outer diameter of the lower portion 1365 of the tubular member 1310 is significantly less than the outer diameters of the upper and intermediate portions, 1355 and 1360, of the tubular member 1310 in order to optimize the formation of a concentric and overlapping arrangement of wellbore casings. In this manner, as will be described below with reference to Figs. 12 and 13, a wellhead system is optimally provided. In a preferred embodiment, the formation of a wellhead system does not include the use of a hardenable fluidic material.

In a particularly preferred embodiment, the wall thickness of the intermediate section 1360 of the tubular member 1310 is less than or equal to the wall thickness of the upper and lower sections, 1355 and 1365, of the tubular member 1310 in order to optimally facilitate the initiation of the extrusion process and optimally permit the placement of the apparatus in areas of the wellbore having tight clearances.

The tubular member 1310 preferably comprises a solid member. In a preferred embodiment, the upper end portion 1355 of the tubular member 1310 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 1305 when it completes the extrusion of tubular member 1310. In a preferred embodiment, the length of the tubular member 1310 is limited to minimize the possibility of buckling. For typical tubular member 1310 materials, the length of the tubular member 1310 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 1315 is coupled to the tubular member 1310. The shoe 1315 preferably includes fluid passages 1330 and 1335. The shoe 1315 may comprise

any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or guide shoe with a sealing sleeve for a latch-down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 1315 comprises an
5 aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 1310 into the wellbore 1200, optimally fluidically isolate the interior of the tubular member 1310, and optimally permit the complete drill out of the shoe 1315 upon
10 the completion of the extrusion and cementing operations.

In a preferred embodiment, the shoe 1315 further includes one or more side outlet ports in fluidic communication with the fluid passage 1330. In this manner, the shoe 1315 preferably injects hardenable fluidic sealing material into the region outside the shoe 1315 and tubular member 1310. In a preferred embodiment, the
15 shoe 1315 includes the fluid passage 1330 having an inlet geometry that can receive a fluidic sealing member. In this manner, the fluid passage 1330 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1330.

The fluid passage 1320 permits fluidic materials to be transported to and
20 from the interior region of the tubular member 1310 below the expandable mandrel 1305. The fluid passage 1320 is coupled to and positioned within the support member 1345 and the expandable mandrel 1305. The fluid passage 1320 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 1305. The fluid passage 1320 is preferably positioned along
25 a centerline of the apparatus 1300. The fluid passage 1320 is preferably selected to transport materials such as cement, drilling mud, or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally provide sufficient operating pressures to circulate fluids at operationally efficient rates.

30 The fluid passage 1330 permits fluidic materials to be transported to and from the region exterior to the tubular member 1310 and shoe 1315. The fluid passage 1330 is coupled to and positioned within the shoe 1315 in fluidic

communication with the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305. The fluid passage 1330 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage 1330 to thereby block further passage of fluidic materials. In this manner, the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305 can be fluidically isolated from the region exterior to the tubular member 1310. This permits the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305 to be pressurized. The fluid passage 1330 is preferably positioned substantially along the centerline of the apparatus 1300.

10 The fluid passage 1330 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 1310 and the new section 1230 of the wellbore 1200 with fluidic materials. In a preferred embodiment, the fluid passage 1330 includes an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 1330 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1320.

20 The fluid passage 1335 permits fluidic materials to be transported to and from the region exterior to the tubular member 1310 and shoe 1315. The fluid passage 1335 is coupled to and positioned within the shoe 1315 in fluidic communication with the fluid passage 1330. The fluid passage 1335 is preferably positioned substantially along the centerline of the apparatus 1300. The fluid passage 1335 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 1310 and the new section 1230 of the wellbore 1200 with fluidic materials.

30 The seals 1340 are coupled to and supported by the upper end portion 1355 of the tubular member 1310. The seals 1340 are further positioned on an outer surface of the upper end portion 1355 of the tubular member 1310. The seals 1340 permit the overlapping joint between the lower end portion of the casing 1215 and the upper portion 1355 of the tubular member 1310 to be fluidically sealed. The

seals 1340 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 1340 comprise seals molded from Stratalock epoxy available from Halliburton
5 Energy Services in Dallas, TX in order to optimally provide a hydraulic seal in the annulus of the overlapping joint while also creating optimal load bearing capability to withstand typical tensile and compressive loads.

In a preferred embodiment, the seals 1340 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 1310 from the
10 existing casing 1215. In a preferred embodiment, the frictional force provided by the seals 1340 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 1310.

The support member 1345 is coupled to the expandable mandrel 1305, tubular member 1310, shoe 1315, and seals 1340. The support member 1345
15 preferably comprises an annular member having sufficient strength to carry the apparatus 1300 into the new section 1230 of the wellbore 1200. In a preferred embodiment, the support member 1345 further includes one or more conventional centralizers (not illustrated) to help stabilize the tubular member 1310.

In a preferred embodiment, the support member 1345 is thoroughly cleaned
20 prior to assembly to the remaining portions of the apparatus 1300. In this manner, the introduction of foreign material into the apparatus 1300 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 1300 and to ensure that no foreign material interferes with the expansion process.

The wiper plug 1350 is coupled to the mandrel 1305 within the interior
25 region 1370 of the tubular member 1310. The wiper plug 1350 includes a fluid passage 1375 that is coupled to the fluid passage 1320. The wiper plug 1350 may comprise one or more conventional commercially available wiper plugs such as, for example, Multiple Stage Cementer latch-down plugs, Omega latch-down plugs or
30 three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the wiper plug 1350 comprises a Multiple Stage Cementer latch-down plug available from Halliburton Energy

Services in Dallas, TX modified in a conventional manner for releasable attachment to the expansion mandrel 1305.

In a preferred embodiment, before or after positioning the apparatus 1300 within the new section 1230 of the wellbore 1200, a couple of wellbore volumes are
5 circulated in order to ensure that no foreign materials are located within the wellbore 1200 that might clog up the various flow passages and valves of the apparatus 1300 and to ensure that no foreign material interferes with the extrusion process.

As illustrated in Fig. 11c, a hardenable fluidic sealing material 1380 is then
10 pumped from a surface location into the fluid passage 1320. The material 1380 then passes from the fluid passage 1320, through the fluid passage 1375, and into the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305. The material 1380 then passes from the interior region 1370 into the fluid passage 1330. The material 1380 then exits the apparatus 1300 via the
15 fluid passage 1335 and fills the annular region 1390 between the exterior of the tubular member 1310 and the interior wall of the new section 1230 of the wellbore 1200. Continued pumping of the material 1380 causes the material 1380 to fill up at least a portion of the annular region 1390.

The material 1380 may be pumped into the annular region 1390 at
20 pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. In a preferred embodiment, the material 1380 is pumped into the annular region 1390 at pressures and flow rates ranging from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively, in order to optimally fill the annular region between the tubular member 1310 and the new section 1230
25 of the wellbore 1200 with the hardenable fluidic sealing material 1380.

The hardenable fluidic sealing material 1380 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 1380 comprises blended cements designed
30 specifically for the well section being drilled and available from Halliburton Energy Services in order to optimally provide support for the tubular member 1310 during

displacement of the material 1380 in the annular region 1390. The optimum blend of the cement is preferably determined using conventional empirical methods.

The annular region 1390 preferably is filled with the material 1380 in sufficient quantities to ensure that, upon radial expansion of the tubular member 1310, the annular region 1390 of the new section 1230 of the wellbore 1200 will be filled with material 1380.

As illustrated in Fig. 11d, once the annular region 1390 has been adequately filled with material 1380, a wiper dart 1395, or other similar device, is introduced into the fluid passage 1320. The wiper dart 1395 is preferably pumped through the fluid passage 1320 by a non hardenable fluidic material 1381. The wiper dart 1395 then preferably engages the wiper plug 1350.

As illustrated in Fig. 11e, in a preferred embodiment, engagement of the wiper dart 1395 with the wiper plug 1350 causes the wiper plug 1350 to decouple from the mandrel 1305. The wiper dart 1395 and wiper plug 1350 then preferably will lodge in the fluid passage 1330, thereby blocking fluid flow through the fluid passage 1330, and fluidically isolating the interior region 1370 of the tubular member 1310 from the annular region 1390. In a preferred embodiment, the non hardenable fluidic material 1381 is then pumped into the interior region 1370 causing the interior region 1370 to pressurize. Once the interior region 1370 becomes sufficiently pressurized, the tubular member 1310 is extruded off of the expandable mandrel 1305. During the extrusion process, the expandable mandrel 1305 is raised out of the expanded portion of the tubular member 1310 by the support member 1345.

The wiper dart 1395 is preferably placed into the fluid passage 1320 by introducing the wiper dart 1395 into the fluid passage 1320 at a surface location in a conventional manner. The wiper dart 1395 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer latch-down plugs, Omega latch-down plugs or three wiper latch-down plug/dart modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the wiper dart 1395 comprises a three wiper latch-down plug modified to latch and seal in the Multiple Stage

Cementer latch down plug 1350. The three wiper latch-down plug is available from Halliburton Energy Services in Dallas, TX.

After blocking the fluid passage 1330 using the wiper plug 1330 and wiper dart 1395, the non hardenable fluidic material 1381 may be pumped into the interior region 1370 at pressures and flow rates ranging, for example, from approximately 0 to 5000 psi and 0 to 1,500 gallons/min in order to optimally extrude the tubular member 1310 off of the mandrel 1305. In this manner, the amount of hardenable fluidic material within the interior of the tubular member 1310 is minimized.

In a preferred embodiment, after blocking the fluid passage 1330, the non hardenable fluidic material 1381 is preferably pumped into the interior region 1370 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to optimally provide operating pressures to maintain the expansion process at rates sufficient to permit adjustments to be made in operating parameters during the extrusion process.

For typical tubular members 1310, the extrusion of the tubular member 1310 off of the expandable mandrel 1305 will begin when the pressure of the interior region 1370 reaches, for example, approximately 500 to 9,000 psi. In a preferred embodiment, the extrusion of the tubular member 1310 off of the expandable mandrel 1305 is a function of the tubular member diameter, wall thickness of the tubular member, geometry of the mandrel, the type of lubricant, the composition of the shoe and tubular member, and the yield strength of the tubular member. The optimum flow rate and operating pressures are preferably determined using conventional empirical methods.

During the extrusion process, the expandable mandrel 1305 may be raised out of the expanded portion of the tubular member 1310 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expandable mandrel 1305 may be raised out of the expanded portion of the tubular member 1310 at rates ranging from about 0 to 2 ft/sec in order to optimally provide an efficient process, optimally permit operator adjustment of operation parameters, and ensure optimal completion of the extrusion process before curing of the material 1380.

When the upper end portion 1355 of the tubular member 1310 is extruded off of the expandable mandrel 1305, the outer surface of the upper end portion 1355 of the tubular member 1310 will preferably contact the interior surface of the lower end portion of the casing 1215 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to optimally provide contact pressure sufficient to ensure annular sealing and provide enough resistance to withstand typical tensile and compressive loads. In a particularly preferred embodiment, the sealing members 1340 will ensure an adequate fluidic and gaseous seal in the overlapping joint.

In a preferred embodiment, the operating pressure and flow rate of the non hardenable fluidic material 1381 is controllably ramped down when the expandable mandrel 1305 reaches the upper end portion 1355 of the tubular member 1310. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 1310 off of the expandable mandrel 1305 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 1305 has completed approximately all but about 5 feet of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 1345 in order to absorb the shock caused by the sudden release of pressure.

Alternatively, or in combination, a mandrel catching structure is provided in the upper end portion 1355 of the tubular member 1310 in order to catch or at least decelerate the mandrel 1305.

Once the extrusion process is completed, the expandable mandrel 1305 is removed from the wellbore 1200. In a preferred embodiment, either before or after the removal of the expandable mandrel 1305, the integrity of the fluidic seal of the overlapping joint between the upper portion 1355 of the tubular member 1310 and the lower portion of the casing 1215 is tested using conventional methods. If the fluidic seal of the overlapping joint between the upper portion 1355 of the tubular

member 1310 and the lower portion of the casing 1215 is satisfactory, then the uncured portion of the material 1380 within the expanded tubular member 1310 is then removed in a conventional manner. The material 1380 within the annular region 1390 is then allowed to cure.

5 As illustrated in Fig. 11f, preferably any remaining cured material 1380 within the interior of the expanded tubular member 1310 is then removed in a conventional manner using a conventional drill string. The resulting new section of casing 1400 includes the expanded tubular member 1310 and an outer annular layer 1405 of cured material 305. The bottom portion of the apparatus 1300
10 comprising the shoe 1315 may then be removed by drilling out the shoe 1315 using conventional drilling methods.

Referring now to Figs. 12 and 13, a preferred embodiment of a wellhead system 1500 formed using one or more of the apparatus and processes described above with reference to Figs. 1-11f will be described. The wellhead system 1500
15 preferably includes a conventional Christmas tree/drilling spool assembly 1505, a thick wall casing 1510, an annular body of cement 1515, an outer casing 1520, an annular body of cement 1525, an intermediate casing 1530, and an inner casing 1535.

The Christmas tree/drilling spool assembly 1505 may comprise any number
20 of conventional Christmas tree/drilling spool assemblies such as, for example, the SS-15 Subsea Wellhead System, Spool Tree Subsea Production System or the Compact Wellhead System available from suppliers such as Dril-Quip, Cameron or Breda, modified in accordance with the teachings of the present disclosure. The drilling spool assembly 1505 is preferably operably coupled to the thick wall casing
25 1510 and/or the outer casing 1520. The assembly 1505 may be coupled to the thick wall casing 1510 and/or outer casing 1520, for example, by welding, a threaded connection or made from single stock. In a preferred embodiment, the assembly 1505 is coupled to the thick wall casing 1510 and/or outer casing 1520 by welding.

The thick wall casing 1510 is positioned in the upper end of a wellbore 1540.
30 In a preferred embodiment, at least a portion of the thick wall casing 1510 extends above the surface 1545 in order to optimally provide easy access and attachment to the Christmas tree/drilling spool assembly 1505. The thick wall casing 1510 is

preferably coupled to the Christmas tree/drilling spool assembly 1505, the annular body of cement 1515, and the outer casing 1520.

The thick wall casing 1510 may comprise any number of conventional commercially available high strength wellbore casings such as, for example, Oilfield Country Tubular Goods, titanium tubing or stainless steel tubing. In a preferred embodiment, the thick wall casing 1510 comprises Oilfield Country Tubular Goods available from various foreign and domestic steel mills. In a preferred embodiment, the thick wall casing 1510 has a yield strength of about 40,000 to 135,000 psi in order to optimally provide maximum burst, collapse, and tensile strengths. In a preferred embodiment, the thick wall casing 1510 has a failure strength in excess of about 5,000 to 20,000 psi in order to optimally provide maximum operating capacity and resistance to degradation of capacity after being drilled through for an extended time period.

The annular body of cement 1515 provides support for the thick wall casing 1510. The annular body of cement 1515 may be provided using any number of conventional processes for forming an annular body of cement in a wellbore. The annular body of cement 1515 may comprise any number of conventional cement mixtures.

The outer casing 1520 is coupled to the thick wall casing 1510. The outer casing 1520 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the outer casing 1520 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

In a preferred embodiment, the outer casing 1520 is coupled to the thick wall casing 1510 by expanding the outer casing 1520 into contact with at least a portion of the interior surface of the thick wall casing 1510 using any one of the embodiments of the processes and apparatus described above with reference to Figs. 1-11f. In an alternative embodiment, substantially all of the overlap of the outer casing 1520 with the thick wall casing 1510 contacts with the interior surface of the thick wall casing 1510.

The contact pressure of the interface between the outer casing 1520 and the thick wall casing 1510 may range, for example, from about 500 to 10,000 psi. In a preferred embodiment, the contact pressure between the outer casing 1520 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to
5 optimally activate the pressure activated sealing members and to ensure that the overlapping joint will optimally withstand typical extremes of tensile and compressive loads that are experienced during drilling and production operations.

As illustrated in Fig. 13, in a particularly preferred embodiment, the upper end of the outer casing 1520 includes one or more sealing members 1550 that
10 provide a gaseous and fluidic seal between the expanded outer casing 1520 and the interior wall of the thick wall casing 1510. The sealing members 1550 may comprise any number of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing
15 members 1550 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit between the tubular members. In a preferred embodiment, the contact pressure of the interface between the thick wall casing 1510 and the outer casing 1520 ranges from about 500 to 10,000 psi in order to
20 optimally activate the sealing members 1550 and also optimally ensure that the joint will withstand the typical operating extremes of tensile and compressive loads during drilling and production operations.

In an alternative preferred embodiment, the outer casing 1520 and the thick walled casing 1510 are combined in one unitary member.

25 The annular body of cement 1525 provides support for the outer casing 1520. In a preferred embodiment, the annular body of cement 1525 is provided using any one of the embodiments of the apparatus and processes described above with reference to Figs. 1-11f.

The intermediate casing 1530 may be coupled to the outer casing 1520 or
30 the thick wall casing 1510. In a preferred embodiment, the intermediate casing 1530 is coupled to the thick wall casing 1510. The intermediate casing 1530 may

be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the intermediate casing 1530 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

5 In a preferred embodiment, the intermediate casing 1530 is coupled to the thick wall casing 1510 by expanding at least a portion of the intermediate casing 1530 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to Figs. 1-11f. In an alternative preferred embodiment, the entire length of the overlap of the
10 intermediate casing 1530 with the thick wall casing 1510 contacts the inner surface of the thick wall casing 1510. The contact pressure of the interface between the intermediate casing 1530 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. In a preferred embodiment, the contact pressure between the intermediate casing 1530 and the thick wall casing 1510
15 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads experienced during drilling and production operations.

As illustrated in Fig. 13, in a particularly preferred embodiment, the upper
20 end of the intermediate casing 1530 includes one or more sealing members 1560 that provide a gaseous and fluidic seal between the expanded end of the intermediate casing 1530 and the interior wall of the thick wall casing 1510. The sealing members 1560 may comprise any number of conventional commercially available seals such as, for example, plastic, lead, rubber, Teflon or epoxy, modified
25 in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 1560 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide a hydraulic seal and a load bearing interference fit between the tubular members.

In a preferred embodiment, the contact pressure of the interface between
30 the expanded end of the intermediate casing 1530 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the sealing

members 1560 and also optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production operations.

The inner casing 1535 may be coupled to the outer casing 1520 or the thick wall casing 1510. In a preferred embodiment, the inner casing 1535 is coupled to the thick wall casing 1510. The inner casing 1535 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the inner casing 1535 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

In a preferred embodiment, the inner casing 1535 is coupled to the outer casing 1520 by expanding at least a portion of the inner casing 1535 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to Figs. 1-11f. In an alternative preferred embodiment, the entire length of the overlap of the inner casing 1535 with the thick wall casing 1510 and intermediate casing 1530 contacts the inner surfaces of the thick wall casing 1510 and intermediate casing 1530. The contact pressure of the interface between the inner casing 1535 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. In a preferred embodiment, the contact pressure between the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to ensure that the joint will withstand typical extremes of tensile and compressive loads that are commonly experienced during drilling and production operations.

As illustrated in Fig. 13, in a particularly preferred embodiment, the upper end of the inner casing 1535 includes one or more sealing members 1570 that provide a gaseous and fluidic seal between the expanded end of the inner casing 1535 and the interior wall of the thick wall casing 1510. The sealing members 1570 may comprise any number of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 1570 comprise seals molded from StrataLock epoxy available from

Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit. In a preferred embodiment, the contact pressure of the interface between the expanded end of the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate
5 the sealing members 1570 and also to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production operations.

In an alternative embodiment, the inner casings, 1520, 1530 and 1535, may be coupled to a previously positioned tubular member that is in turn coupled to the
10 outer casing 1510. More generally, the present preferred embodiments may be used to form a concentric arrangement of tubular members.

Referring now to Figures 14a, 14b, 14c, 14d, 14e and 14f, a preferred embodiment of a method and apparatus for forming a mono-diameter well casing within a subterranean formation will now be described.

As illustrated in Fig. 14a, a wellbore 1600 is positioned in a subterranean
15 formation 1605. A first section of casing 1610 is formed in the wellbore 1600. The first section of casing 1610 includes an annular outer body of cement 1615 and a tubular section of casing 1620. The first section of casing 1610 may be formed in the wellbore 1600 using conventional methods and apparatus. In a preferred
20 embodiment, the first section of casing 1610 is formed using one or more of the methods and apparatus described above with reference to Figs. 1-13 or below with reference to Figs. 14b-17b.

The annular body of cement 1615 may comprise any number of conventional commercially available cement, or other load bearing, compositions. Alternatively,
25 the body of cement 1615 may be omitted or replaced with an epoxy mixture.

The tubular section of casing 1620 preferably includes an upper end 1625 and a lower end 1630. Preferably, the lower end 1625 of the tubular section of casing 1620 includes an outer annular recess 1635 extending from the lower end 1630 of the tubular section of casing 1620. In this manner, the lower end 1625 of
30 the tubular section of casing 1620 includes a thin walled section 1640. In a preferred embodiment, an annular body 1645 of a compressible material is coupled to and at least partially positioned within the outer annular recess 1635. In this

manner, the body of compressible material 1645 surrounds at least a portion of the thin walled section 1640.

The tubular section of casing 1620 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, carbon steel, low alloy steel, fiberglass or plastics. In a preferred embodiment, the tubular section of casing 1620 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills. The wall thickness of the thin walled section 1640 may range from about 0.125 to 1.5 inches. In a preferred embodiment, the wall thickness of the thin walled section 1640 ranges from 0.25 to 1.0 inches in order to optimally provide burst strength for typical operational conditions while also minimizing resistance to radial expansion. The axial length of the thin walled section 1640 may range from about 120 to 2400 inches. In a preferred embodiment, the axial length of the thin walled section 1640 ranges from about 240 to 480 inches.

The annular body of compressible material 1645 helps to minimize the radial force required to expand the tubular casing 1620 in the overlap with the tubular member 1715, helps to create a fluidic seal in the overlap with the tubular member 1715, and helps to create an interference fit sufficient to permit the tubular member 1715 to be supported by the tubular casing 1620. The annular body of compressible material 1645 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or lead tubes. In a preferred embodiment, the annular body of compressible material 1645 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint while also having compliance to thereby minimize the radial force required to expand the tubular casing. The wall thickness of the annular body of compressible material 1645 may range from about 0.05 to 0.75 inches. In a preferred embodiment, the wall thickness of the annular body of compressible material 1645 ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible zone, minimize the radial forces required to expand the tubular

casing, provide thickness for casing strings to provide contact with the inner surface of the wellbore upon radial expansion, and provide an hydraulic seal.

As illustrated in Fig. 14b, in order to extend the wellbore 1600 into the subterranean formation 1605, a drill string is used in a well known manner to drill out material from the subterranean formation 1605 to form a new wellbore section 1650. The diameter of the new section 1650 is preferably equal to or greater than the inner diameter of the tubular section of casing 1620.

As illustrated in Fig. 14c, a preferred embodiment of an apparatus 1700 for forming a mono-diameter wellbore casing in a subterranean formation is then positioned in the new section 1650 of the wellbore 1600. The apparatus 1700 preferably includes a support member 1705, an expandable mandrel or pig 1710, a tubular member 1715, a shoe 1720, slips 1725, a fluid passage 1730, one or more fluid passages 1735, a fluid passage 1740, a first compressible annular body 1745, a second compressible annular body 1750, and a pressure chamber 1755.

The support member 1705 supports the apparatus 1700 within the wellbore 1600. The support member 1705 is coupled to the mandrel 1710, the tubular member 1715, the shoe 1720, and the slips 1725. The support member 1075 preferably comprises a substantially hollow tubular member. The fluid passage 1730 is positioned within the support member 1705. The fluid passages 1735 fluidically couple the fluid passage 1730 with the pressure chamber 1755. The fluid passage 1740 fluidically couples the fluid passage 1730 with the region outside of the apparatus 1700.

The support member 1705 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, 13 chromium steel, fiberglass, or other high strength materials. In a preferred embodiment, the support member 1705 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide operational strength and facilitate the use of other standard oil exploration handling equipment. In a preferred embodiment, at least a portion of the support member 1705 comprises coiled tubing or a drill pipe. In a particularly preferred

embodiment, the support member 1705 includes a load shoulder 1820 for supporting the mandrel 1710 when the pressure chamber 1755 is unpressurized.

The mandrel 1710 is supported by and slidingly coupled to the support member 1705 and the shoe 1720. The mandrel 1710 preferably includes an upper portion 1760 and a lower portion 1765. Preferably, the upper portion 1760 of the
5 mandrel 1710 and the support member 1705 together define the pressure chamber 1755. Preferably, the lower portion 1765 of the mandrel 1710 includes an expansion member 1770 for radially expanding the tubular member 1715.

In a preferred embodiment, the upper portion 1760 of the mandrel 1710
10 includes a tubular member 1775 having an inner diameter greater than an outer diameter of the support member 1705. In this manner, an annular pressure chamber 1755 is defined by and positioned between the tubular member 1775 and the support member 1705. The top 1780 of the tubular member 1775 preferably includes a bearing and a seal for sealing and supporting the top 1780 of the tubular
15 member 1775 against the outer surface of the support member 1705. The bottom 1785 of the tubular member 1775 preferably includes a bearing and seal for sealing and supporting the bottom 1785 of the tubular member 1775 against the outer surface of the support member 1705 or shoe 1720. In this manner, the mandrel 1710 moves in an axial direction upon the pressurization of the pressure chamber
20 1755.

The lower portion 1765 of the mandrel 1710 preferably includes an expansion member 1770 for radially expanding the tubular member 1715 during the pressurization of the pressure chamber 1755. In a preferred embodiment, the expansion member is expandable in the radial direction. In a preferred
25 embodiment, the inner surface of the lower portion 1765 of the mandrel 1710 mates with and slides with respect to the outer surface of the shoe 1720. The outer diameter of the expansion member 1770 may range from about 90 to 100 % of the inner diameter of the tubular casing 1620. In a preferred embodiment, the outer diameter of the expansion member 1770 ranges from about 95 to 99 % of the inner
30 diameter of the tubular casing 1620. The expansion member 1770 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, titanium or other

high strength alloys. In a preferred embodiment, the expansion member 1770 is fabricated from D2 machine tool steel in order to optimally provide high strength and abrasion resistance.

The tubular member 1715 is coupled to and supported by the support member 1705 and slips 1725. The tubular member 1715 includes an upper portion 1790 and a lower portion 1795.

The upper portion 1790 of the tubular member 1715 preferably includes an inner annular recess 1800 that extends from the upper portion 1790 of the tubular member 1715. In this manner, at least a portion of the upper portion 1790 of the tubular member 1715 includes a thin walled section 1805. The first compressible annular member 1745 is preferably coupled to and supported by the outer surface of the upper portion 1790 of the tubular member 1715 in opposing relation to the thin wall section 1805.

The lower portion 1795 of the tubular member 1715 preferably includes an outer annular recess 1810 that extends from the lower portion 1790 of the tubular member 1715. In this manner, at least a portion of the lower portion 1795 of the tubular member 1715 includes a thin walled section 1815. The second compressible annular member 1750 is coupled to and at least partially supported within the outer annular recess 1810 of the upper portion 1790 of the tubular member 1715 in opposing relation to the thin wall section 1815.

The tubular member 1715 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, automotive grade steel, fiberglass, 13 chrome steel, other high strength material, or high strength plastics. In a preferred embodiment, the tubular member 1715 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide operational strength.

The shoe 1720 is supported by and coupled to the support member 1705. The shoe 1720 preferably comprises a substantially hollow tubular member. In a preferred embodiment, the wall thickness of the shoe 1720 is greater than the wall thickness of the support member 1705 in order to optimally provide increased radial support to the mandrel 1710. The shoe 1720 may be fabricated from any

number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, low alloy steel, carbon steel, or high strength plastics. In a preferred embodiment, the shoe 1720 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide matching operational strength throughout the apparatus.

The slips 1725 are coupled to and supported by the support member 1705. The slips 1725 removably support the tubular member 1715. In this manner, during the radial expansion of the tubular member 1715, the slips 1725 help to maintain the tubular member 1715 in a substantially stationary position by preventing upward movement of the tubular member 1715.

The slips 1725 may comprise any number of conventional commercially available slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips, or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the slips 1725 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services. In a preferred embodiment, the slips 1725 are adapted to support axial forces ranging from about 0 to 750,000 lbf.

The fluid passage 1730 conveys fluidic materials from a surface location into the interior of the support member 1705, the pressure chamber 1755, and the region exterior of the apparatus 1700. The fluid passage 1730 is fluidically coupled to the pressure chamber 1755 by the fluid passages 1735. The fluid passage 1730 is fluidically coupled to the region exterior to the apparatus 1700 by the fluid passage 1740.

In a preferred embodiment, the fluid passage 1730 is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, slag mix, water or drilling gasses. In a preferred embodiment, the fluid passage 1730 is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi. in order to optimally provide flow rates and operational pressures for the radial expansion processes.

The fluid passages 1735 convey fluidic material from the fluid passage 1730 to the pressure chamber 1755. In a preferred embodiment, the fluid passage 1735

is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, water or drilling gasses. In a preferred embodiment, the fluid passage 1735 is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 500 gallons/minute and 0 to 9,000 psi. in order to optimally provide
5 operating pressures and flow rates for the various expansion processes.

The fluid passage 1740 conveys fluidic materials from the fluid passage 1730 to the region exterior to the apparatus 1700. In a preferred embodiment, the fluid passage 1740 is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, water or drilling gasses. In a preferred embodiment, the fluid
10 passage 1740 is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi. in order to optimally provide operating pressures and flow rates for the various radial expansion processes.

In a preferred embodiment, the fluid passage 1740 is adapted to receive a
15 plug or other similar device for sealing the fluid passage 1740. In this manner, the pressure chamber 1755 may be pressurized.

The first compressible annular body 1745 is coupled to and supported by an exterior surface of the upper portion 1790 of the tubular member 1715. In a preferred embodiment, the first compressible annular body 1745 is positioned in
20 opposing relation to the thin walled section 1805 of the tubular member 1715.

The first compressible annular body 1745 helps to minimize the radial force required to expand the tubular member 1715 in the overlap with the tubular casing 1620, helps to create a fluidic seal in the overlap with the tubular casing 1620, and helps to create an interference fit sufficient to permit the tubular
25 member 1715 to be supported by the tubular casing 1620. The first compressible annular body 1745 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics, or hollow lead tubes. In a preferred embodiment, the first compressible annular body 1745 comprises StrataLock epoxy available from Halliburton Energy Services in
30 order to optimally provide an hydraulic seal, and compressibility to minimize the radial expansion force.

The wall thickness of the first compressible annular body 1745 may range from about 0.05 to 0.75 inches. In a preferred embodiment, the wall thickness of the first compressible annular body 1745 ranges from about 0.1 to 0.5 inches in order to optimally (1) provide a large compressible zone, (2) minimize the required radial expansion force, (3) transfer the radial force to the tubular casings. As a result, in a preferred embodiment, overall the outer diameter of the tubular member 1715 is approximately equal to the overall inner diameter of the tubular member 1620.

The second compressible annular body 1750 is coupled to and at least partially supported within the outer annular recess 1810 of the tubular member 1715. In a preferred embodiment, the second compressible annular body 1750 is positioned in opposing relation to the thin walled section 1815 of the tubular member 1715.

The second compressible annular body 1750 helps to minimize the radial force required to expand the tubular member 1715 in the overlap with another tubular member, helps to create a fluidic seal in the overlap of the tubular member 1715 with another tubular member, and helps to create an interference fit sufficient to permit another tubular member to be supported by the tubular member 1715. The second compressible annular body 1750 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or hollow lead tubing. In a preferred embodiment, the first compressible annular body 1750 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint, and compressibility that minimizes the radial expansion force.

The wall thickness of the second compressible annular body 1750 may range from about 0.05 to 0.75 inches. In a preferred embodiment, the wall thickness of the second compressible annular body 1750 ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible zone, and minimize the radial force required to expand the tubular member 1715 during subsequent radial expansion operations.

In an alternative embodiment, the outside diameter of the second compressible annular body 1750 is adapted to provide a seal against the surrounding formation thereby eliminating the need for an outer annular body of cement.

5 The pressure chamber 1755 is fluidly coupled to the fluid passage 1730 by the fluid passages 1735. The pressure chamber 1755 is preferably adapted to receive fluidic materials such as, for example, drilling muds, water or drilling gases. In a preferred embodiment, the pressure chamber 1755 is adapted to receive fluidic materials at flow rate and pressures ranging from about 0 to 500
10 gallons/minute and 0 to 9,000 psi. in order to optimally provide expansion pressure. In a preferred embodiment, during pressurization of the pressure chamber 1755, the operating pressure of the pressure chamber ranges from about 0 to 5,000 psi in order to optimally provide expansion pressure while minimizing the possibility of a catastrophic failure due to over pressurization.

15 As illustrated in Fig. 14d, the apparatus 1700 is preferably positioned in the wellbore 1600 with the tubular member 1715 positioned in an overlapping relationship with the tubular casing 1620. In a particularly preferred embodiment, the thin wall sections, 1640 and 1805, of the tubular casing 1620 and tubular member 1725 are positioned in opposing overlapping relation. In this manner, the
20 radial expansion of the tubular member 1725 will compress the thin wall sections, 1640 and 1805, and annular compressible members, 1645 and 1745, into intimate contact.

After positioning of the apparatus 1700, a fluidic material 1825 is then pumped into the fluid passage 1730. The fluidic material 1825 may comprise any
25 number of conventional commercially available materials such as, for example, water, drilling mud, drilling gases, cement or epoxy. In a preferred embodiment, the fluidic material 1825 comprises a hardenable fluidic sealing material such as, for example, cement in order to provide an outer annular body around the expanded tubular member 1715.

30 The fluidic material 1825 may be pumped into the fluid passage 1730 at operating pressures and flow rates, for example, ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The fluidic material 1825 pumped into the fluid passage 1730 passes through the fluid passage 1740 and outside of the apparatus 1700. The fluidic material 1825 fills the annular region 1830 between the outside of the apparatus 1700 and the interior walls of the wellbore 1600.

5 As illustrated in Fig. 14e, a plug 1835 is then introduced into the fluid passage 1730. The plug 1835 lodges in the inlet to the fluid passage 1740 fluidically isolating and blocking off the fluid passage 1730.

A fluidic material 1840 is then pumped into the fluid passage 1730. The fluidic material 1840 may comprise any number of conventional commercially
10 available materials such as, for example, water, drilling mud or drilling gases. In a preferred embodiment, the fluidic material 1825 comprises a non-hardenable fluidic material such as, for example, drilling mud or drilling gases in order to optimally provide pressurization of the pressure chamber 1755.

The fluidic material 1840 may be pumped into the fluid passage 1730 at
15 operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 500 gallons/minute. In a preferred embodiment, the fluidic material 1840 is pumped into the fluid passage 1730 at operating pressures and flow rates ranging from about 500 to 5,000 psi and 0 to 500 gallons/minute in order to optimally provide operating pressures and flow rates for radial expansion.

20 The fluidic material 1840 pumped into the fluid passage 1730 passes through the fluid passages 1735 and into the pressure chamber 1755. Continued pumping of the fluidic material 1840 pressurizes the pressure chamber 1755. The pressurization of the pressure chamber 1755 causes the mandrel 1710 to move relative to the support member 1705 in the direction indicated by the arrows 1845.
25 In this manner, the mandrel 1710 will cause the tubular member 1715 to expand in the radial direction.

During the radial expansion process, the tubular member 1715 is prevented from moving in an upward direction by the slips 1725. A length of the tubular member 1715 is then expanded in the radial direction through the pressurization
30 of the pressure chamber 1755. The length of the tubular member 1715 that is expanded during the expansion process will be proportional to the stroke length of the mandrel 1710. Upon the completion of a stroke, the operating pressure of

the pressure chamber 1755 is then reduced and the mandrel 1710 drops to its rest position with the tubular member 1715 supported by the mandrel 1715. The position of the support member 1705 may be adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections, 1640 and 1805, of the tubular casing 1620 and tubular member 1715. The stroking of the mandrel 1710 is then repeated, as necessary, until the thin walled section 1805 of the tubular member 1715 is expanded into the thin walled section 1640 of the tubular casing 1620.

In a preferred embodiment, during the final stroke of the mandrel 1710, the slips 1725 are positioned as close as possible to the thin walled section 1805 of the tubular member 1715 in order to minimize slippage between the tubular member 1715 and tubular casing 1620 at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the first compressive annular member 1745 is selected to ensure sufficient interference fit with the tubular casing 1620 to prevent axial displacement of the tubular member 1715 during the final stroke. Alternatively, or in addition, the outside diameter of the second compressive annular body 1750 is large enough to provide an interference fit with the inside walls of the wellbore 1600 at an earlier point in the radial expansion process so as to prevent further axial displacement of the tubular member 1715. In this final alternative, the interference fit is preferably selected to permit expansion of the tubular member 1715 by pulling the mandrel 1710 out of the wellbore 1600, without having to pressurize the pressure chamber 1755.

During the radial expansion process, the pressurized areas of the apparatus 1700 are limited to the fluid passages 1730 within the support member 1705 and the pressure chamber 1755 within the mandrel 1710. No fluid pressure acts directly on the tubular member 1715. This permits the use of operating pressures higher than the tubular member 1715 could normally withstand.

Once the tubular member 1715 has been completely expanded off of the mandrel 1710, the support member 1705 and mandrel 1710 are removed from the wellbore 1600. In a preferred embodiment, the contact pressure between the deformed thin wall sections, 1640 and 1805, and compressible annular members,

1645 and 1745, ranges from about 400 to 10,000 psi in order to optimally support the tubular member 1715 using the tubular casing 1620.

In this manner, the tubular member 1715 is radially expanded into contact with the tubular casing 1620 by pressurizing the interior of the fluid passage 1730
5 and the pressure chamber 1755.

As illustrated in Fig. 14f, in a preferred embodiment, once the tubular member 1715 is completely expanded in the radial direction by the mandrel 1710, the support member 1705 and mandrel 1710 are removed from the wellbore 1600. In a preferred embodiment, the annular body of hardenable fluidic material is then
10 allowed to cure to form a rigid outer annular body 1850. In the case where the tubular member 1715 is slotted, the hardenable fluidic material will preferably permeate and envelop the expanded tubular member 1715.

The resulting new section of wellbore casing 1855 includes the expanded tubular member 1715 and the rigid outer annular body 1850. The overlapping
15 joint 1860 between the tubular casing 1620 and the expanded tubular member 1715 includes the deformed thin wall sections, 1640 and 1805, and the compressible annular bodies, 1645 and 1745. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular
20 members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

Referring now to Figures 15, 15a and 15b, an embodiment of an apparatus
25 1900 for expanding a tubular member will be described. The apparatus 1900 preferably includes a drillpipe 1905, an innerstring adapter 1910, a sealing sleeve 1915, an inner sealing mandrel 1920, an upper sealing head 1925, a lower sealing head 1930, an outer sealing mandrel 1935, a load mandrel 1940, an expansion cone 1945, a mandrel launcher 1950, a mechanical slip body 1955, mechanical slips
30 1960, drag blocks 1965, casing 1970, and fluid passages 1975, 1980, 1985, and 1990.

The drillpipe 1905 is coupled to the innerstring adapter 1910. During operation of the apparatus 1900, the drillpipe 1905 supports the apparatus 1900. The drillpipe 1905 preferably comprises a substantially hollow tubular member or members. The drillpipe 1905 may be fabricated from any number of conventional
5 commercially available materials such as, for example, oilfield country tubular drillpipe, fiberglass or coiled tubing. In a preferred embodiment, the drillpipe 1905 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 1900 in non-vertical wellbores. The drillpipe 1905 may be coupled to the innerstring adapter 1910 using any number of conventional commercially available
10 mechanical couplings such as, for example, drillpipe connectors, OCTG specialty type box and pin connectors, a ratchet-latch type connector or a standard box by pin connector. In a preferred embodiment, the drillpipe 1905 is removably coupled to the innerstring adapter 1910 by a drillpipe connection.

The drillpipe 1905 preferably includes a fluid passage 1975 that is adapted
15 to convey fluidic materials from a surface location into the fluid passage 1980. In a preferred embodiment, the fluid passage 1975 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

20 The innerstring adapter 1910 is coupled to the drill string 1905 and the sealing sleeve 1915. The innerstring adapter 1910 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 1910 may be fabricated from any number of conventional commercially available materials such as, for example, oil country tubular goods, low alloy steel, carbon
25 steel, stainless steel or other high strength materials. In a preferred embodiment, the innerstring adapter 1910 is fabricated from oilfield country tubular goods in order to optimally provide mechanical properties that closely match those of the drill string 1905.

The innerstring adapter 1910 may be coupled to the drill string 1905 using
30 any number of conventional commercially available mechanical couplings such as, for example, drillpipe connectors, oilfield country tubular goods specialty type threaded connectors, ratchet-latch type stab in connector, or a standard threaded

connection. In a preferred embodiment, the innerstring adapter 1910 is removably coupled to the drill pipe 1905 by a drillpipe connection. The innerstring adapter 1910 may be coupled to the sealing sleeve 1915 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe
5 connection, oilfield country tubular goods specialty type threaded connector, ratchet-latch type stab in connectors, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 1910 is removably coupled to the sealing sleeve 1915 by a standard threaded connection.

The innerstring adapter 1910 preferably includes a fluid passage 1980 that
10 is adapted to convey fluidic materials from the fluid passage 1975 into the fluid passage 1985. In a preferred embodiment, the fluid passage 1980 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

15 The sealing sleeve 1915 is coupled to the innerstring adapter 1910 and the inner sealing mandrel 1920. The sealing sleeve 1915 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 1915 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, carbon steel, low alloy steel,
20 stainless steel or other high strength materials. In a preferred embodiment, the sealing sleeve 1915 is fabricated from oilfield country tubular goods in order to optimally provide mechanical properties that substantially match the remaining components of the apparatus 1900.

The sealing sleeve 1915 may be coupled to the innerstring adapter 1910
25 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type stab in connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 1915 is removably coupled to the innerstring adapter 1910 by a standard threaded
30 connection. The sealing sleeve 1915 may be coupled to the inner sealing mandrel 1920 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods

specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 1915 is removably coupled to the inner sealing mandrel 1920 by a standard threaded connection.

5 The sealing sleeve 1915 preferably includes a fluid passage 1985 that is adapted to convey fluidic materials from the fluid passage 1980 into the fluid passage 1990. In a preferred embodiment, the fluid passage 1985 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

10 The inner sealing mandrel 1920 is coupled to the sealing sleeve 1915 and the lower sealing head 1930. The inner sealing mandrel 1920 preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel 1920 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel or other similar high strength materials. In a preferred
15 embodiment, the inner sealing mandrel 1920 is fabricated from stainless steel in order to optimally provide mechanical properties similar to the other components of the apparatus 1900 while also providing a smooth outer surface to support seals and other moving parts that can operate with minimal wear, corrosion and pitting.

20 The inner sealing mandrel 1920 may be coupled to the sealing sleeve 1915 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 1920 is removably coupled to the sealing
25 sleeve 1915 by a standard threaded connections. The inner sealing mandrel 1920 may be coupled to the lower sealing head 1930 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type stab in connectors or standard threaded connections. In a
30 preferred embodiment, the inner sealing mandrel 1920 is removably coupled to the lower sealing head 1930 by a standard threaded connections connection.

The inner sealing mandrel 1920 preferably includes a fluid passage 1990 that is adapted to convey fluidic materials from the fluid passage 1985 into the fluid passage 1995. In a preferred embodiment, the fluid passage 1990 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The upper sealing head 1925 is coupled to the outer sealing mandrel 1935 and the expansion cone 1945. The upper sealing head 1925 is also movably coupled to the outer surface of the inner sealing mandrel 1920 and the inner surface of the casing 1970. In this manner, the upper sealing head 1925, outer sealing mandrel 1935, and the expansion cone 1945 reciprocate in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head 1925 and the outer surface of the inner sealing mandrel 1920 may range, for example, from about 0.025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 1925 and the outer surface of the inner sealing mandrel 1920 ranges from about 0.005 to 0.01 inches in order to optimally provide clearance for pressure seal placement. The radial clearance between the outer cylindrical surface of the upper sealing head 1925 and the inner surface of the casing 1970 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 1925 and the inner surface of the casing 1970 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 1945 as the expansion cone 1945 is upwardly moved inside the casing 1970.

The upper sealing head 1925 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 1925 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, machine tool steel, or similar high strength materials. In a preferred embodiment, the upper sealing head 1925 is fabricated from stainless steel in order to optimally provide high strength and smooth outer surfaces that are resistant to wear, galling, corrosion and pitting.

The inner surface of the upper sealing head 1925 preferably includes one or more annular sealing members 2000 for sealing the interface between the upper sealing head 1925 and the inner sealing mandrel 1920. The sealing members 2000 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2000 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial motion.

In a preferred embodiment, the upper sealing head 1925 includes a shoulder 2005 for supporting the upper sealing head 1925 on the lower sealing head 1930.

The upper sealing head 1925 may be coupled to the outer sealing mandrel 1935 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connections. In a preferred embodiment, the upper sealing head 1925 is removably coupled to the outer sealing mandrel 1935 by a standard threaded connections. In a preferred embodiment, the mechanical coupling between the upper sealing head 1925 and the outer sealing mandrel 1935 includes one or more sealing members 2010 for fluidically sealing the interface between the upper sealing head 1925 and the outer sealing mandrel 1935. The sealing members 2010 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2010 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroking motion.

The lower sealing head 1930 is coupled to the inner sealing mandrel 1920 and the load mandrel 1940. The lower sealing head 1930 is also movably coupled to the inner surface of the outer sealing mandrel 1935. In this manner, the upper sealing head 1925 and outer sealing mandrel 1935 reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head 1930 and the inner surface of the outer sealing mandrel 1935 may range, for example, from about 0.025 to 0.05 inches. In a preferred embodiment, the radial

clearance between the outer surface of the lower sealing head 1930 and the inner surface of the outer sealing mandrel 1935 ranges from about 0.005 to 0.010 inches in order to optimally provide a close tolerance having room for the installation of pressure seal rings.

5 The lower sealing head 1930 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head 1930 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, machine tool steel or other similar high strength materials. In a preferred
10 embodiment, the lower sealing head 1930 is fabricated from stainless steel in order to optimally provide high strength and resistance to wear, galling, corrosion, and pitting.

 The outer surface of the lower sealing head 1930 preferably includes one or more annular sealing members 2015 for sealing the interface between the lower
15 sealing head 1930 and the outer sealing mandrel 1935. The sealing members 2015 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2015 comprise polypak
20 seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

 The lower sealing head 1930 may be coupled to the inner sealing mandrel 1920 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard
25 threaded connection. In a preferred embodiment, the lower sealing head 1930 is removably coupled to the inner sealing mandrel 1920 by a standard threaded connection.

 In a preferred embodiment, the mechanical coupling between the lower sealing head 1930 and the inner sealing mandrel 1920 includes one or more sealing
30 members 2020 for fluidicly sealing the interface between the lower sealing head 1930 and the inner sealing mandrel 1920. The sealing members 2020 may comprise any number of conventional commercially available sealing members

such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2020 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial motion.

The lower sealing head 1930 may be coupled to the load mandrel 1940 using
5 any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the lower sealing head 1930 is removably coupled to the load mandrel 1940 by a standard threaded connection. In a
10 preferred embodiment, the mechanical coupling between the lower sealing head 1930 and the load mandrel 1940 includes one or more sealing members 2025 for fluidically sealing the interface between the lower sealing head 1930 and the load mandrel 1940. The sealing members 2025 may comprise any number of conventional commercially available sealing members such as, for example, o-rings,
15 polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2025 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the lower sealing head 1930 includes a throat passage 2040 fluidically coupled between the fluid passages 1990 and 1995. The
20 throat passage 2040 is preferably of reduced size and is adapted to receive and engage with a plug 2045, or other similar device. In this manner, the fluid passage 1990 is fluidically isolated from the fluid passage 1995. In this manner, the pressure chamber 2030 is pressurized.

The outer sealing mandrel 1935 is coupled to the upper sealing head 1925
25 and the expansion cone 1945. The outer sealing mandrel 1935 is also movably coupled to the inner surface of the casing 1970 and the outer surface of the lower sealing head 1930. In this manner, the upper sealing head 1925, outer sealing mandrel 1935, and the expansion cone 1945 reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel 1935 and
30 the inner surface of the casing 1970 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the outer sealing mandrel 1935 and the inner surface of the casing 1970

ranges from about 0.025 to 0.125 inches in order to optimally provide maximum piston surface area to maximize the radial expansion force. The radial clearance between the inner surface of the outer sealing mandrel 1935 and the outer surface of the lower sealing head 1930 may range, for example, from about 0.025 to 0.05
5 inches. In a preferred embodiment, the radial clearance between the inner surface of the outer sealing mandrel 1935 and the outer surface of the lower sealing head 1930 ranges from about 0.005 to 0.010 inches in order to optimally provide a minimum gap for the sealing elements to bridge and seal.

The outer sealing mandrel 1935 preferably comprises an annular member
10 having substantially cylindrical inner and outer surfaces. The outer sealing mandrel 1935 may be fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, 13 chromium steel or stainless steel. In a preferred embodiment, the outer sealing mandrel 1935 is fabricated from stainless steel in order to optimally provide maximum strength
15 and minimum wall thickness while also providing resistance to corrosion, galling and pitting.

The outer sealing mandrel 1935 may be coupled to the upper sealing head 1925 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods
20 specialty type threaded connection, standard threaded connections, or welding. In a preferred embodiment, the outer sealing mandrel 1935 is removably coupled to the upper sealing head 1925 by a standard threaded connections connection. The outer sealing mandrel 1935 may be coupled to the expansion cone 1945 using any number of conventional commercially available mechanical couplings such as, for
25 example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connections connection, or welding. In a preferred embodiment, the outer sealing mandrel 1935 is removably coupled to the expansion cone 1945 by a standard threaded connections connection.

The upper sealing head 1925, the lower sealing head 1930, the inner sealing
30 mandrel 1920, and the outer sealing mandrel 1935 together define a pressure chamber 2030. The pressure chamber 2030 is fluidically coupled to the passage 1990 via one or more passages 2035. During operation of the apparatus 1900, the plug

2045 engages with the throat passage 2040 to fluidically isolate the fluid passage 1990 from the fluid passage 1995. The pressure chamber 2030 is then pressurized which in turn causes the upper sealing head 1925, outer sealing mandrel 1935, and expansion cone 1945 to reciprocate in the axial direction. The axial motion of the
5 expansion cone 1945 in turn expands the casing 1970 in the radial direction.

The load mandrel 1940 is coupled to the lower sealing head 1930 and the mechanical slip body 1955. The load mandrel 1940 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 1940 may be fabricated from any number of conventional
10 commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 1940 is fabricated from oilfield country tubular goods in order to optimally provide high strength.

The load mandrel 1940 may be coupled to the lower sealing head 1930 using
15 any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection; oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the load mandrel 1940 is removably coupled to the lower sealing head 1930 by a standard threaded connection. The
20 load mandrel 1940 may be coupled to the mechanical slip body 1955 using any number of conventional commercially available mechanical couplings such as, for example, a drillpipe connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding, or a standard threaded connections connection. In a preferred embodiment, the load mandrel 1940 is
25 removably coupled to the mechanical slip body 1955 by a standard threaded connections connection.

The load mandrel 1940 preferably includes a fluid passage 1995 that is adapted to convey fluidic materials from the fluid passage 1990 to the region outside of the apparatus 1900. In a preferred embodiment, the fluid passage 1995
30 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 1945 is coupled to the outer sealing mandrel 1935. The expansion cone 1945 is also movably coupled to the inner surface of the casing 1970. In this manner, the upper sealing head 1925, outer sealing mandrel 1935, and the expansion cone 1945 reciprocate in the axial direction. The reciprocation
5 of the expansion cone 1945 causes the casing 1970 to expand in the radial direction.

The expansion cone 1945 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In
10 a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide cone dimensions for the typical range of tubular members.

The axial length of the expansion cone 1945 may range, for example, from about 2 to 8 times the largest outer diameter of the expansion cone 1945. In a
15 preferred embodiment, the axial length of the expansion cone 1945 ranges from about 3 to 5 times the largest outer diameter of the expansion cone 1945 in order to optimally provide stability and centralization of the expansion cone 1945 during the expansion process. In a preferred embodiment, the angle of attack of the expansion cone 1945 ranges from about 5 to 30 degrees in order to optimally
20 balance friction forces with the desired amount of radial expansion. The expansion cone 1945 angle of attack will vary as a function of the operating parameters of the particular expansion operation.

The expansion cone 1945 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool
25 steel, ceramics, tungsten carbide, nitride steel, or other similar high strength materials. In a preferred embodiment, the expansion cone 1945 is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to corrosion, wear, galling, and pitting. In a particularly preferred embodiment, the outside surface of the expansion cone 1945 has a surface hardness ranging
30 from about 58 to 62 Rockwell C in order to optimally provide high strength and resist wear and galling.

The expansion cone 1945 may be coupled to the outside sealing mandrel 1935 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield tubular country goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connections connection. In a preferred embodiment, the expansion cone 1945 is coupled to the outside sealing mandrel 1935 using a standard threaded connections connection in order to optimally provide connector strength for the typical operating loading conditions while also permitting easy replacement of the expansion cone 1945.

10 The mandrel launcher 1950 is coupled to the casing 1970. The mandrel launcher 1950 comprises a tubular section of casing having a reduced wall thickness compared to the casing 1970. In a preferred embodiment, the wall thickness of the mandrel launcher is about 50 to 100 % of the wall thickness of the casing 1970. In this manner, the initiation of the radial expansion of the casing 15 1970 is facilitated, and the insertion of the larger outside diameter mandrel launcher 1950 into the wellbore and/or casing is facilitated.

The mandrel launcher 1950 may be coupled to the casing 1970 using any number of conventional mechanical couplings. The mandrel launcher 1950 may have a wall thickness ranging, for example, from about 0.15 to 1.5 inches. In a preferred embodiment, the wall thickness of the mandrel launcher 1950 ranges from about 0.25 to 0.75 inches in order to optimally provide high strength with a small overall profile. The mandrel launcher 1950 may be fabricated from any number of conventional commercially available materials such as, for example, oil field tubular goods, low alloy steel, carbon steel, stainless steel or other similar 20 high strength materials. In a preferred embodiment, the mandrel launcher 1950 is fabricated from oil field tubular goods of higher strength but lower wall thickness than the casing 1970 in order to optimally provide a thin walled container with approximately the same burst strength as the casing 1970.

The mechanical slip body 1955 is coupled to the load mandrel 1970, the 30 mechanical slips 1960, and the drag blocks 1965. The mechanical slip body 1955 preferably comprises a tubular member having an inner passage 2050 fluidically

coupled to the passage 1995. In this manner, fluidic materials may be conveyed from the passage 2050 to a region outside of the apparatus 1900.

The mechanical slip body 1955 may be coupled to the load mandrel 1940 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 1955 is removably coupled to the load mandrel 1940 using a standard threaded connection in order to optimally provide high strength and permit the mechanical slip body 1955 to be easily replaced. The mechanical slip body 1955 may be coupled to the mechanical slips 1955 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 1955 is removably coupled to the mechanical slips 1955 using threads and sliding steel retainer rings in order to optimally provide high strength coupling and also permit easy replacement of the mechanical slips 1955. The mechanical slip body 1955 may be coupled to the drag blocks 1965 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 1955 is removably coupled to the drag blocks 1965 using threaded connections and sliding steel retainer rings in order to optimally provide high strength and also permit easy replacement of the drag blocks 1965.

The mechanical slips 1960 are coupled to the outside surface of the mechanical slip body 1955. During operation of the apparatus 1900, the mechanical slips 1960 prevent upward movement of the casing 1970 and mandrel launcher 1950. In this manner, during the axial reciprocation of the expansion cone 1945, the casing 1970 and mandrel launcher 1950 are maintained in a substantially stationary position. In this manner, the mandrel launcher 1950 and casing 1970 are expanded in the radial direction by the axial movement of the expansion cone 1945.

The mechanical slips 1960 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the mechanical slips 1960 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to

optimally provide resistance to axial movement of the casing 1970 during the expansion process.

The drag blocks 1965 are coupled to the outside surface of the mechanical slip body 1955. During operation of the apparatus 1900, the drag blocks 1965 prevent upward movement of the casing 1970 and mandrel launcher 1950. In this manner, during the axial reciprocation of the expansion cone 1945, the casing 1970 and mandrel launcher 1950 are maintained in a substantially stationary position. In this manner, the mandrel launcher 1950 and casing 1970 are expanded in the radial direction by the axial movement of the expansion cone 1945.

10 The drag blocks 1965 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the drag blocks 1965 comprise RTTS packer tungsten
15 carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 1970 during the expansion process.

The casing 1970 is coupled to the mandrel launcher 1950. The casing 1970 is further removably coupled to the mechanical slips 1960 and drag blocks 1965.
20 The casing 1970 preferably comprises a tubular member. The casing 1970 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oil field country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the casing 1970 is fabricated from oilfield country tubular goods
25 available from various foreign and domestic steel mills in order to optimally provide high strength. In a preferred embodiment, the upper end of the casing 1970 includes one or more sealing members positioned about the exterior of the casing 1970.

During operation, the apparatus 1900 is positioned in a wellbore with the
30 upper end of the casing 1970 positioned in an overlapping relationship within an existing wellbore casing. In order minimize surge pressures within the borehole during placement of the apparatus 1900, the fluid passage 1975 is preferably

provided with one or more pressure relief passages. During the placement of the apparatus 1900 in the wellbore, the casing 1970 is supported by the expansion cone 1945.

After positioning of the apparatus 1900 within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic material is pumped into the fluid passage 1975 from a surface location. The first fluidic material is conveyed from the fluid passage 1975 to the fluid passages 1980, 1985, 1990, 1995, and 2050. The first fluidic material will then exit the apparatus and fill the annular region between the outside of the apparatus 1900 and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy or cement. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement or epoxy. In this manner, a wellbore casing having an outer annular layer of a hardenable material may be formed.

The first fluidic material may be pumped into the apparatus 1900 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi, and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the apparatus 1900 at operating pressures and flow rates ranging from about 0 to 4,500 psi and 0 to 3,000 gallons/minute in order to optimally provide operating pressures and flow rates for typical operating conditions.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus 1900 has been filled to a predetermined level, a plug 2045, dart, or other similar device is introduced into the first fluidic material. The plug 2045 lodges in the throat passage 2040 thereby fluidically isolating the fluid passage 1990 from the fluid passage 1995.

After placement of the plug 2045 in the throat passage 2040, a second fluidic material is pumped into the fluid passage 1975 in order to pressurize the pressure chamber 2030. The second fluidic material may comprise any number of

conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant in order minimize frictional forces.

5 The second fluidic material may be pumped into the apparatus 1900 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the apparatus 1900 at operating pressures and flow rates ranging from about 0 to 3,500 psi, and 0 to 1,200 gallons/minute in order to
10 optimally provide expansion of the casing 1970.

 The pressurization of the pressure chamber 2030 causes the upper sealing head 1925, outer sealing mandrel 1935, and expansion cone 1945 to move in an axial direction. As the expansion cone 1945 moves in the axial direction, the expansion cone 1945 pulls the mandrel launcher 1950 and drag blocks 1965 along,
15 which sets the mechanical slips 1960 and stops further axial movement of the mandrel launcher 1950 and casing 1970. In this manner, the axial movement of the expansion cone 1945 radially expands the mandrel launcher 1950 and casing 1970.

 Once the upper sealing head 1925, outer sealing mandrel 1935, and
20 expansion cone 1945 complete an axial stroke, the operating pressure of the second fluidic material is reduced and the drill string 1905 is raised. This causes the inner sealing mandrel 1920, lower sealing head 1930, load mandrel 1940, and mechanical slip body 1955 to move upward. This unsets the mechanical slips 1960 and permits the mechanical slips 1960 and drag blocks 1965 to be moved upward within the
25 mandrel launcher and casing 1970. When the lower sealing head 1930 contacts the upper sealing head 1925, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher 1950 and casing 1970 are radial expanded through repeated axial strokes of the upper sealing head 1925, outer sealing mandrel 1935 and expansion cone 1945.
30 Throughput the radial expansion process, the upper end of the casing 1970 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 1970 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the sealing members provided at the upper end of the casing 1970 provide a fluidic seal between the outside surface of the upper end of the casing 1970 and the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the contact pressure between the casing 1970 and the existing section of wellbore casing ranges from about 400 to 10,000 psi in order to optimally provide contact pressure for activating sealing members, provide optimal resistance to axial movement of the expanded casing 1970, and optimally support typical tensile and compressive loads.

In a preferred embodiment, as the expansion cone 1945 nears the end of the casing 1970, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus 1900. In an alternative embodiment, the apparatus 1900 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 1970.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 1945 nears the end of the casing 1970 in order to optimally provide reduced axial movement and velocity of the expansion cone 1945. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 1900 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 1945. In a preferred embodiment, the stroke length of the apparatus 1900 ranges from about 10 to 45 feet in order to optimally provide equipment lengths that can be handled by typical oil well rigging equipment while also minimizing the frequency at which the expansion cone 1945 must be stopped so the apparatus 1900 can be re-stroked for further expansion operations.

In an alternative embodiment, at least a portion of the upper sealing head 1925 includes an expansion cone for radially expanding the mandrel launcher 1950 and casing 1970 during operation of the apparatus 1900 in order to increase the

surface area of the casing 1970 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

In an alternative embodiment, mechanical slips are positioned in an axial location between the sealing sleeve 1915 and the inner sealing mandrel 1920 in order to simplify the operation and assembly of the apparatus 1900.

Upon the complete radial expansion of the casing 1970, if applicable, the first fluidic material is permitted to cure within the annular region between the outside of the expanded casing 1970 and the interior walls of the wellbore. In the case where the expanded casing 1970 is slotted, the cured fluidic material will preferably permeate and envelop the expanded casing. In this manner, a new section of wellbore casing is formed within a wellbore. Alternatively, the apparatus 1900 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 1900 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 1900 may be used to expand a tubular support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus 1900 are limited to the fluid passages 1975, 1980, 1985, and 1990, and the pressure chamber 2030. No fluid pressure acts directly on the mandrel launcher 1950 and casing 1970. This permits the use of operating pressures higher than the mandrel launcher 1950 and casing 1970 could normally withstand.

Referring now to Figure 16, a preferred embodiment of an apparatus 2100 for forming a mono-diameter wellbore casing will be described. The apparatus 2100 preferably includes a drillpipe 2105, an innerstring adapter 2110, a sealing sleeve 2115, an inner sealing mandrel 2120, slips 2125, upper sealing head 2130, lower sealing head 2135, outer sealing mandrel 2140, load mandrel 2145, expansion cone 2150, and casing 2155.

The drillpipe 2105 is coupled to the innerstring adapter 2110. During operation of the apparatus 2100, the drillpipe 2105 supports the apparatus 2100. The drillpipe 2105 preferably comprises a substantially hollow tubular member or members. The drillpipe 2105 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular

goods, low alloy steel, carbon steel, stainless steel or other similar high strength material. In a preferred embodiment, the drillpipe 2105 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 1900 in non-vertical wellbores. The drillpipe 2105 may be coupled to the innerstring adapter 2110
5 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 2105 is removably coupled to the innerstring adapter 2110 by a drill pipe connection.

10 The drillpipe 2105 preferably includes a fluid passage 2160 that is adapted to convey fluidic materials from a surface location into the fluid passage 2165. In a preferred embodiment, the fluid passage 2160 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to
15 3,000 gallons/minute.

The innerstring adapter 2110 is coupled to the drill string 2105 and the sealing sleeve 2115. The innerstring adapter 2110 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2110 may be fabricated from any number of conventional commercially available
20 materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the innerstring adapter 2110 is fabricated from stainless steel in order to optimally provide high strength, low friction, and resistance to corrosion and wear.

25 The innerstring adapter 2110 may be coupled to the drill string 2105 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2110 is removably
30 coupled to the drill pipe 2105 by a drillpipe connection. The innerstring adapter 2110 may be coupled to the sealing sleeve 2115 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe

connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2110 is removably coupled to the sealing sleeve 2115 by a standard threaded connection.

5 The innerstring adapter 2110 preferably includes a fluid passage 2165 that is adapted to convey fluidic materials from the fluid passage 2160 into the fluid passage 2170. In a preferred embodiment, the fluid passage 2165 is adapted to convey fluidic materials such as, for example, cement, epoxy, water drilling muds, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000
10 psi and 0 to 3,000 gallons/minute.

 The sealing sleeve 2115 is coupled to the innerstring adapter 2110 and the inner sealing mandrel 2120. The sealing sleeve 2115 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 2115 may be fabricated from any number of conventional commercially available materials
15 such as, for example, oil field tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 2115 is fabricated from stainless steel in order to optimally provide high strength, low friction surfaces, and resistance to corrosion, wear, galling, and pitting.

20 The sealing sleeve 2115 may be coupled to the innerstring adapter 2110 using any number of conventional commercially available mechanical couplings such as, for example, a standard threaded connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2115
25 is removably coupled to the innerstring adapter 2110 by a standard threaded connection. The sealing sleeve 2115 may be coupled to the inner sealing mandrel 2120 using any number of conventional commercially available mechanical couplings such as, for example, a standard threaded connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding,
30 or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2115 is removably coupled to the inner sealing mandrel 2120 by a standard threaded connection.

The sealing sleeve 2115 preferably includes a fluid passage 2170 that is adapted to convey fluidic materials from the fluid passage 2165 into the fluid passage 2175. In a preferred embodiment, the fluid passage 2170 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The inner sealing mandrel 2120 is coupled to the sealing sleeve 2115, slips 2125, and the lower sealing head 2135. The inner sealing mandrel 2120 preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel 2120 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the inner sealing mandrel 2120 is fabricated from stainless steel in order to optimally provide high strength, low friction surfaces, and corrosion and wear resistance.

The inner sealing mandrel 2120 may be coupled to the sealing sleeve 2115 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2120 is removably coupled to the sealing sleeve 2115 by a standard threaded connection. The standard threaded connection provides high strength and permits easy replacement of components. The inner sealing mandrel 2120 may be coupled to the slips 2125 using any number of conventional commercially available mechanical couplings such as, for example, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2120 is removably coupled to the slips 2125 by a standard threaded connection. The inner sealing mandrel 2120 may be coupled to the lower sealing head 2135 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred

embodiment, the inner sealing mandrel 2120 is removably coupled to the lower sealing head 2135 by a standard threaded connection.

The inner sealing mandrel 2120 preferably includes a fluid passage 2175 that is adapted to convey fluidic materials from the fluid passage 2170 into the fluid passage 2180. In a preferred embodiment, the fluid passage 2175 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips 2125 are coupled to the outer surface of the inner sealing mandrel 2120. During operation of the apparatus 2100, the slips 2125 preferably maintain the casing 2155 in a substantially stationary position during the radial expansion of the casing 2155. In a preferred embodiment, the slips 2125 are activated using the fluid passages 2185 to convey pressurized fluid material into the slips 2125.

The slips 2125 may comprise any number of commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug hydraulic slips. In a preferred embodiment, the slips 2125 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2155 during the expansion process. In a particularly preferred embodiment, the slips include a fluid passage 2190, pressure chamber 2195, spring return 2200, and slip member 2205.

The slips 2125 may be coupled to the inner sealing mandrel 2120 using any number of conventional mechanical couplings. In a preferred embodiment, the slips 2125 are removably coupled to the outer surface of the inner sealing mandrel 2120 by a thread connection in order to optimally provide interchangeability of parts.

The upper sealing head 2130 is coupled to the outer sealing mandrel 2140 and expansion cone 2150. The upper sealing head 2130 is also movably coupled to the outer surface of the inner sealing mandrel 2120 and the inner surface of the casing 2155. In this manner, the upper sealing head 2130 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head 2130 and the outer surface of the inner sealing mandrel 2120 may

range, for example, from about 0.025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 2130 and the outer surface of the inner sealing mandrel 2120 ranges from about 0.005 to 0.010 inches in order to optimally provide a pressure seal. The radial
5 clearance between the outer cylindrical surface of the upper sealing head 2130 and the inner surface of the casing 2155 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 2130 and the inner surface of the casing 2155 ranges from about 0.025 to 0.125 inches in order to optimally provide
10 stabilization for the expansion cone 2130 during axial movement of the expansion cone 2130.

The upper sealing head 2130 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 2130 may be fabricated from any number of conventional commercially available
15 materials such as, for example, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the upper sealing head 2130 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the upper sealing head 2130 preferably includes one or more annular sealing members
20 2210 for sealing the interface between the upper sealing head 2130 and the inner sealing mandrel 2120. The sealing members 2210 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2210 comprise polypak seals available from
25 Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the upper sealing head 2130 includes a shoulder 2215 for supporting the upper sealing head 2130 on the lower sealing head 2135.

The upper sealing head 2130 may be coupled to the outer sealing mandrel
30 2140 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded

connection. In a preferred embodiment, the upper sealing head 2130 is removably coupled to the outer sealing mandrel 2140 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the upper sealing head 2130 and the outer sealing mandrel 2140 includes one or more sealing members 5 2220 for fluidically sealing the interface between the upper sealing head 2130 and the outer sealing mandrel 2140. The sealing members 2220 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2220 comprise polypak seals available from 10 Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2135 is coupled to the inner sealing mandrel 2120 and the load mandrel 2145. The lower sealing head 2135 is also movably coupled to the inner surface of the outer sealing mandrel 2140. In this manner, the upper sealing head 2130, outer sealing mandrel 2140, and expansion cone 2150 15 reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head 2135 and the inner surface of the outer sealing mandrel 2140 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the lower sealing head 2135 and the inner surface of the outer sealing mandrel 2140 ranges from 20 about 0.0025 to 0.05 inches in order to optimally provide minimal radial clearance.

The lower sealing head 2135 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head 2135 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, 25 carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the lower sealing head 2135 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the lower sealing head 2135 preferably includes one or more annular sealing members 2225 for sealing the interface between the lower sealing 30 head 2135 and the outer sealing mandrel 2140. The sealing members 2225 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized

seals. In a preferred embodiment, the sealing members 2225 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2135 may be coupled to the inner sealing mandrel
5 2120 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the lower sealing head 2135 is removably coupled to the inner sealing mandrel 2120 by a standard threaded
10 connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2135 and the inner sealing mandrel 2120 includes one or more sealing members 2230 for fluidicly sealing the interface between the lower sealing head 2135 and the inner sealing mandrel 2120. The sealing members 2230 may comprise any number of conventional commercially available sealing members
15 such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2230 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2135 may be coupled to the load mandrel 2145 using any number of conventional commercially available mechanical couplings such as,
20 for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the lower sealing head 2135 is removably coupled to the load mandrel 2145 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2135 and
25 the load mandrel 2145 includes one or more sealing members 2235 for fluidicly sealing the interface between the lower sealing head 1930 and the load mandrel 2145. The sealing members 2235 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing
30 members 2235 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the lower sealing head 2135 includes a throat passage 2240 fluidically coupled between the fluid passages 2175 and 2180. The throat passage 2240 is preferably of reduced size and is adapted to receive and engage with a plug 2245, or other similar device. In this manner, the fluid passage
5 2175 is fluidically isolated from the fluid passage 2180. In this manner, the pressure chamber 2250 is pressurized.

The outer sealing mandrel 2140 is coupled to the upper sealing head 2130 and the expansion cone 2150. The outer sealing mandrel 2140 is also movably coupled to the inner surface of the casing 2155 and the outer surface of the lower
10 sealing head 2135. In this manner, the upper sealing head 2130, outer sealing mandrel 2140, and the expansion cone 2150 reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel 2140 and the inner surface of the casing 2155 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer
15 surface of the outer sealing mandrel 2140 and the inner surface of the casing 2155 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2130 during the expansion process. The radial clearance between the inner surface of the outer sealing mandrel 2140 and the outer surface of the lower sealing head 2135 may range, for example, from about 0.005 to 0.125
20 inches. In a preferred embodiment, the radial clearance between the inner surface of the outer sealing mandrel 2140 and the outer surface of the lower sealing head 2135 ranges from about 0.005 to 0.010 inches in order to optimally provide minimal radial clearance.

The outer sealing mandrel 2140 preferably comprises an annular member
25 having substantially cylindrical inner and outer surfaces. The outer sealing mandrel 2140 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the outer sealing mandrel 2140 is fabricated from stainless
30 steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel 2140 may be coupled to the upper sealing head 2130 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2140 is removably coupled to the upper sealing head 2130 by a standard threaded connection. The outer sealing mandrel 2140 may be coupled to the expansion cone 2150 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2140 is removably coupled to the expansion cone 2150 by a standard threaded connection.

The upper sealing head 2130, the lower sealing head 2135, inner sealing mandrel 2120, and the outer sealing mandrel 2140 together define a pressure chamber 2250. The pressure chamber 2250 is fluidically coupled to the passage 2175 via one or more passages 2255. During operation of the apparatus 2100, the plug 2245 engages with the throat passage 2240 to fluidically isolate the fluid passage 2175 from the fluid passage 2180. The pressure chamber 2250 is then pressurized which in turn causes the upper sealing head 2130, outer sealing mandrel 2140, and expansion cone 2150 to reciprocate in the axial direction. The axial motion of the expansion cone 2150 in turn expands the casing 2155 in the radial direction.

The load mandrel 2145 is coupled to the lower sealing head 2135. The load mandrel 2145 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 2145 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 2145 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction bearing surfaces.

The load mandrel 2145 may be coupled to the lower sealing head 2135 using any number of conventional commercially available mechanical couplings such as,

for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the load mandrel 2145 is removably coupled to the lower sealing head 2135 by a standard threaded connection in order to optimally provide
5 high strength and permit easy replacement of the load mandrel 2145.

The load mandrel 2145 preferably includes a fluid passage 2180 that is adapted to convey fluidic materials from the fluid passage 2180 to the region outside of the apparatus 2100. In a preferred embodiment, the fluid passage 2180 is adapted to convey fluidic materials such as, for example, cement, epoxy, water,
10 drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 2150 is coupled to the outer sealing mandrel 2140. The expansion cone 2150 is also movably coupled to the inner surface of the casing 2155. In this manner, the upper sealing head 2130, outer sealing mandrel 2140,
15 and the expansion cone 2150 reciprocate in the axial direction. The reciprocation of the expansion cone 2150 causes the casing 2155 to expand in the radial direction.

The expansion cone 2150 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of
20 the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide cone dimensions that are optimal for typical casings. The axial length of the expansion cone 2150 may range, for example, from about 2 to 6 times the largest outside diameter of the
25 expansion cone 2150. In a preferred embodiment, the axial length of the expansion cone 2150 ranges from about 3 to 5 times the largest outside diameter of the expansion cone 2150 in order to optimally provide stability and centralization of the expansion cone 2150 during the expansion process. In a particularly preferred embodiment, the maximum outside diameter of the expansion cone 2150 is
30 between about 90 to 100 % of the inside diameter of the existing wellbore that the casing 2155 will be joined with. In a preferred embodiment, the angle of attack of the expansion cone 2150 ranges from about 5 to 30 degrees in order to optimally

balance friction forces and radial expansion forces. The optimal expansion cone 2150 angle of attack will vary as a function of the particular operating conditions of the expansion operation.

5 The expansion cone 2150 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics, or other similar high strength materials. In a preferred embodiment, the expansion cone 2150 is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to wear and galling. In a particularly preferred embodiment, the
10 outside surface of the expansion cone 2150 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide resistance to wear.

The expansion cone 2150 may be coupled to the outside sealing mandrel 2140 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods
15 specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the expansion cone 2150 is coupled to the outside sealing mandrel 2140 using a standard threaded connection in order to optimally provide high strength and permit the expansion cone 2150 to be easily replaced.

20 The casing 2155 is removably coupled to the slips 2125 and expansion cone 2150. The casing 2155 preferably comprises a tubular member. The casing 2155 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength material. In
25 a preferred embodiment, the casing 2155 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength.

In a preferred embodiment, the upper end 2260 of the casing 2155 includes a thin wall section 2265 and an outer annular sealing member 2270. In a preferred
30 embodiment, the wall thickness of the thin wall section 2265 is about 50 to 100 % of the regular wall thickness of the casing 2155. In this manner, the upper end 2260 of the casing 2155 may be easily expanded and deformed into intimate

contact with the lower end of an existing section of wellbore casing. In a preferred embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section 2265 of casing 2155 into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member 2270 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the annular sealing member 2270 is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the annular sealing member 2270 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the wellbore casing that the casing 2155 is joined to. In this manner, after expansion, the annular sealing member 2270 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing 2155 to support the casing 2155.

In a preferred embodiment, the lower end 2275 of the casing 2155 includes a thin wall section 2280 and an outer annular sealing member 2285. In a preferred embodiment, the wall thickness of the thin wall section 2280 is about 50 to 100 % of the regular wall thickness of the casing 2155. In this manner, the lower end 2275 of the casing 2155 may be easily expanded and deformed. Furthermore, in this manner, an other section of casing may be easily joined with the lower end 2275 of the casing 2155 using a radial expansion process. In a preferred embodiment, the upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section of the upper end of the other casing into the thin walled section 2280 of the lower end of the casing 2155 results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member 2285 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the annular sealing member 2285 is fabricated from StrataLock epoxy in order to optimally provide

compressibility and wear resistance. The outside diameter of the annular sealing member 2285 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 2155 is joined to. In this manner, the annular sealing member 2285 preferably provides a fluidic seal
5 and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 2155 to support the casing 2155.

During operation, the apparatus 2100 is preferably positioned in a wellbore with the upper end 2260 of the casing 2155 positioned in an overlapping relationship with the lower end of an existing wellbore casing. In a particularly
10 preferred embodiment, the thin wall section 2265 of the casing 2155 is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing 2155 will compress the thin wall sections and annular compressible members of the upper end 2260 of the casing
15 2155 and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus 2100 in the wellbore, the casing 2155 is supported by the expansion cone 2150.

After positioning of the apparatus 2100, a first fluidic material is then pumped into the fluid passage 2160. The first fluidic material may comprise any
20 number of conventional commercially available materials such as, for example, drilling mud, water, epoxy, or cement. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement or epoxy in order to provide a hardenable outer annular body around the expanded casing 2155.

25 The first fluidic material may be pumped into the fluid passage 2160 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the fluid passage 2160 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to
30 optimally provide operational efficiency.

The first fluidic material pumped into the fluid passage 2160 passes through the fluid passages 2165, 2170, 2175, 2180 and then outside of the apparatus 2100.

The first fluidic material then fills the annular region between the outside of the apparatus 2100 and the interior walls of the wellbore.

The plug 2245 is then introduced into the fluid passage 2160. The plug 2245 lodges in the throat passage 2240 and fluidically isolates and blocks off the fluid passage 2175. In a preferred embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage 2160 in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

A second fluidic material is then pumped into the fluid passage 2160. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, drilling gases, or lubricants. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant in order to optimally provide pressurization of the pressure chamber 2250 and minimize frictional forces.

The second fluidic material may be pumped into the fluid passage 2160 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the fluid passage 2160 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The second fluidic material pumped into the fluid passage 2160 passes through the fluid passages 2165, 2170, and 2175 into the pressure chambers 2195 of the slips 2125, and into the pressure chamber 2250. Continued pumping of the second fluidic material pressurizes the pressure chambers 2195 and 2250.

The pressurization of the pressure chambers 2195 causes the slip members 2205 to expand in the radial direction and grip the interior surface of the casing 2155. The casing 2155 is then preferably maintained in a substantially stationary position.

The pressurization of the pressure chamber 2250 causes the upper sealing head 2130, outer sealing mandrel 2140 and expansion cone 2150 to move in an

axial direction relative to the casing 2155. In this manner, the expansion cone 2150 will cause the casing 2155 to expand in the radial direction.

During the radial expansion process, the casing 2155 is prevented from moving in an upward direction by the slips 2125. A length of the casing 2155 is then expanded in the radial direction through the pressurization of the pressure chamber 2250. The length of the casing 2155 that is expanded during the expansion process will be proportional to the stroke length of the upper sealing head 2130, outer sealing mandrel 2140, and expansion cone 2150.

Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the upper sealing head 2130, outer sealing mandrel 2140, and expansion cone 2150 drop to their rest positions with the casing 2155 supported by the expansion cone 2150. The position of the drillpipe 2105 is preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing 2155. In a preferred embodiment, the stroking of the expansion cone 2150 is then repeated, as necessary, until the thin walled section 2265 of the upper end 2260 of the casing 2155 is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

In a preferred embodiment, during the final stroke of the expansion cone 2150, the slips 2125 are positioned as close as possible to the thin walled section 2265 of the upper end of the casing 2155 in order to minimize slippage between the casing 2155 and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the annular sealing member 2270 is selected to ensure sufficient interference fit with the inside diameter of the lower end of the existing casing to prevent axial displacement of the casing 2155 during the final stroke. Alternatively, or in addition, the outside diameter of the annular sealing member 2285 is selected to provide an interference

fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further axial displacement of the casing 2155. In this final alternative, the interference fit is preferably selected to permit expansion of the casing 2155 by pulling the expansion cone 2150 out of the wellbore, without
5 having to pressurize the pressure chamber 2250.

During the radial expansion process, the pressurized areas of the apparatus 2100 are limited to the fluid passages 2160, 2165, 2170, and 2175, the pressure chambers 2195 within the slips 2125, and the pressure chamber 2250. No fluid pressure acts directly on the casing 2155. This permits the use of operating
10 pressures higher than the casing 2155 could normally withstand.

Once the casing 2155 has been completely expanded off of the expansion cone 2150, remaining portions of the apparatus 2100 are removed from the wellbore. In a preferred embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the
15 existing casing and the upper end 2260 of the casing 2155 ranges from about 500 to 40,000 psi in order to optimally support the casing 2155 using the existing wellbore casing.

In this manner, the casing 2155 is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages 2160, 2165,
20 2170, and 2175 and the pressure chamber 2250 of the apparatus 2100.

In a preferred embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing 2155. In the case where the casing 2155 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2155. The
25 resulting new section of wellbore casing includes the expanded casing 2155 and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing 2155 includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-
30 diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a

mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In a preferred embodiment, as the expansion cone 2150 nears the upper end of the casing 2155, the operating flow rate of the second fluidic material is reduced
5 in order to minimize shock to the apparatus 2100. In an alternative embodiment, the apparatus 2100 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2155.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2130
10 nears the end of the casing 2155 in order to optimally provide reduced axial movement and velocity of the expansion cone 2130. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2100 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 2130 during the return
15 stroke. In a preferred embodiment, the stroke length of the apparatus 2100 ranges from about 10 to 45 feet in order to optimally provide equipment lengths that can be handled by conventional oil well rigging equipment while also minimizing the frequency at which the expansion cone 2130 must be stopped so that the apparatus 2100 can be re-stroked.

20 In an alternative embodiment, at least a portion of the upper sealing head 2130 includes an expansion cone for radially expanding the casing 2155 during operation of the apparatus 2100 in order to increase the surface area of the casing 2155 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

25 Alternatively, the apparatus 2100 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2100 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2100 may be used to expand a tubular support member in a hole.

30 Referring now to Figures 17, 17a and 17b, another embodiment of an apparatus 2300 for expanding a tubular member will be described. The apparatus 2300 preferably includes a drillpipe 2305, an innerstring adapter 2310, a sealing

sleeve 2315, a hydraulic slip body 2320, hydraulic slips 2325, an inner sealing mandrel 2330, an upper sealing head 2335, a lower sealing head 2340, a load mandrel 2345, an outer sealing mandrel 2350, an expansion cone 2355, a mechanical slip body 2360, mechanical slips 2365, drag blocks 2370, casing 2375, fluid passages 2380, 2385, 2390, 2395, 2400, 2405, 2410, 2415, and 2485, and mandrel launcher 2480.

The drillpipe 2305 is coupled to the innerstring adapter 2310. During operation of the apparatus 2300, the drillpipe 2305 supports the apparatus 2300. The drillpipe 2305 preferably comprises a substantially hollow tubular member or members. The drillpipe 2305 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the drillpipe 2305 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 2300 in non-vertical wellbores. The drillpipe 2305 may be coupled to the innerstring adapter 2310 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 2305 is removably coupled to the innerstring adapter 2310 by a drillpipe connection.

The drillpipe 2305 preferably includes a fluid passage 2380 that is adapted to convey fluidic materials from a surface location into the fluid passage 2385. In a preferred embodiment, the fluid passage 2380 is adapted to convey fluidic materials such as, for example, cement, water, epoxy, drilling muds, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 5,000 gallons/minute in order to optimally provide operational efficiency.

The innerstring adapter 2310 is coupled to the drill string 2305 and the sealing sleeve 2315. The innerstring adapter 2310 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2310 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred

embodiment, the innerstring adapter 2310 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter 2310 may be coupled to the drill string 2305 using
5 any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2310 is removably coupled to the drill pipe 2305 by a drillpipe connection. The innerstring adapter 2310 may be coupled to the sealing sleeve
10 2315 using any number of conventional commercially available mechanical couplings such as, for example, a drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2310 is removably coupled to the sealing sleeve 2315 by a standard threaded connection.

15 The innerstring adapter 2310 preferably includes a fluid passage 2385 that is adapted to convey fluidic materials from the fluid passage 2380 into the fluid passage 2390. In a preferred embodiment, the fluid passage 2385 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, drilling gases or lubricants at operating pressures and flow rates ranging from
20 about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 2315 is coupled to the innerstring adapter 2310 and the hydraulic slip body 2320. The sealing sleeve 2315 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 2315 may be fabricated from any number of conventional commercially available materials
25 such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 2315 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low-friction surfaces.

The sealing sleeve 2315 may be coupled to the innerstring adapter 2310
30 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty threaded connections, or a standard threaded connection. In a preferred

embodiment, the sealing sleeve 2315 is removably coupled to the innerstring adapter 2310 by a standard threaded connection. The sealing sleeve 2315 may be coupled to the hydraulic slip body 2320 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe
5 connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2315 is removably coupled to the hydraulic slip body 2320 by a standard threaded connection.

The sealing sleeve 2315 preferably includes a fluid passage 2390 that is
10 adapted to convey fluidic materials from the fluid passage 2385 into the fluid passage 2395. In a preferred embodiment, the fluid passage 2315 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

15 The hydraulic slip body 2320 is coupled to the sealing sleeve 2315, the hydraulic slips 2325, and the inner sealing mandrel 2330. The hydraulic slip body 2320 preferably comprises a substantially hollow tubular member or members. The hydraulic slip body 2320 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular
20 goods, low alloy steel, carbon steel, stainless steel or other high strength material. In a preferred embodiment, the hydraulic slip body 2320 is fabricated from carbon steel in order to optimally provide high strength at low cost.

The hydraulic slip body 2320 may be coupled to the sealing sleeve 2315 using any number of conventional commercially available mechanical couplings
25 such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2320 is removably coupled to the sealing sleeve 2315 by a standard threaded connection. The hydraulic slip body 2320 may be coupled to the slips 2325 using any number of conventional commercially
30 available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the hydraulic slip

body 2320 is removably coupled to the slips 2325 by a standard threaded connection. The hydraulic slip body 2320 may be coupled to the inner sealing mandrel 2330 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country
5 tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2320 is removably coupled to the inner sealing mandrel 2330 by a standard threaded connection.

The hydraulic slips body 2320 preferably includes a fluid passage 2395 that
10 is adapted to convey fluidic materials from the fluid passage 2390 into the fluid passage 2405. In a preferred embodiment, the fluid passage 2395 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

15 The hydraulic slips body 2320 preferably includes fluid passage 2400 that are adapted to convey fluidic materials from the fluid passage 2395 into the pressure chambers 2420 of the hydraulic slips 2325. In this manner, the slips 2325 are activated upon the pressurization of the fluid passage 2395 into contact with the inside surface of the casing 2375. In a preferred embodiment, the fluid
20 passages 2400 are adapted to convey fluidic materials such as, for example, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips 2325 are coupled to the outside surface of the hydraulic slip body 2320. During operation of the apparatus 2300, the slips 2325 are activated upon
25 the pressurization of the fluid passage 2395 into contact with the inside surface of the casing 2375. In this manner, the slips 2325 maintain the casing 2375 in a substantially stationary position.

The slips 2325 preferably include the fluid passages 2400, the pressure chambers 2420, spring bias 2425, and slip members 2430. The slips 2325 may
30 comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In a preferred embodiment, the slips

2325 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2375 during the radial expansion process.

The inner sealing mandrel 2330 is coupled to the hydraulic slip body 2320
5 and the lower sealing head 2340. The inner sealing mandrel 2330 preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel 2330 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a
10 preferred embodiment, the inner sealing mandrel 2330 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The inner sealing mandrel 2330 may be coupled to the hydraulic slip body 2320 using any number of conventional commercially available mechanical
15 couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2330 is removably coupled to the hydraulic slip body 2320 by a standard threaded connection. The inner sealing mandrel 2330 may be coupled to the lower sealing
20 head 2340 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2330 is removably coupled to the lower sealing head 2340 by a standard threaded
25 connection.

The inner sealing mandrel 2330 preferably includes a fluid passage 2405 that is adapted to convey fluidic materials from the fluid passage 2395 into the fluid passage 2415. In a preferred embodiment, the fluid passage 2405 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling
30 mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The upper sealing head 2335 is coupled to the outer sealing mandrel 2345 and expansion cone 2355. The upper sealing head 2335 is also movably coupled to the outer surface of the inner sealing mandrel 2330 and the inner surface of the casing 2375. In this manner, the upper sealing head 2335 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head 2335 and the outer surface of the inner sealing mandrel 2330 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 2335 and the outer surface of the inner sealing mandrel 2330 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal clearance. The radial clearance between the outer cylindrical surface of the upper sealing head 2335 and the inner surface of the casing 2375 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 2335 and the inner surface of the casing 2375 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2355 during the expansion process.

The upper sealing head 2335 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 2335 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the upper sealing head 2335 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the upper sealing head 2335 preferably includes one or more annular sealing members 2435 for sealing the interface between the upper sealing head 2335 and the inner sealing mandrel 2330. The sealing members 2435 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2435 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the upper sealing head 2335 includes a shoulder 2440 for supporting the upper sealing head on the lower sealing head 1930.

The upper sealing head 2335 may be coupled to the outer sealing mandrel 2350 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the upper sealing head 2335 is removably coupled to the outer sealing mandrel 2350 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the upper sealing head 2335 and the outer sealing mandrel 2350 includes one or more sealing members 2445 for fluidically sealing the interface between the upper sealing head 2335 and the outer sealing mandrel 2350. The sealing members 2445 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2445 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The lower sealing head 2340 is coupled to the inner sealing mandrel 2330 and the load mandrel 2345. The lower sealing head 2340 is also movably coupled to the inner surface of the outer sealing mandrel 2350. In this manner, the upper sealing head 2335 and outer sealing mandrel 2350 reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head 2340 and the inner surface of the outer sealing mandrel 2350 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the lower sealing head 2340 and the inner surface of the outer sealing mandrel 2350 ranges from about 0.005 to 0.010 inches in order to optimally provide minimal radial clearance.

The lower sealing head 2340 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head 2340 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubular members, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the lower sealing head 2340 is fabricated from stainless steel in order

to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the lower sealing head 2340 preferably includes one or more annular sealing members 2450 for sealing the interface between the lower sealing head 2340 and the outer sealing mandrel 2350. The sealing members 2450 may
5 comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2450 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

10 The lower sealing head 2340 may be coupled to the inner sealing mandrel 2330 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular specialty threaded connection, welding, amorphous bonding, or standard threaded connection. In a preferred embodiment, the lower sealing head 2340 is removably
15 coupled to the inner sealing mandrel 2330 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2340 and the inner sealing mandrel 2330 includes one or more sealing members 2455 for fluidically sealing the interface between the lower sealing head 2340 and the inner sealing mandrel 2330. The sealing members 2455 may comprise any
20 number of conventional commercially available sealing members such as, for example, o-rings, polypak or metal spring energized seals. In a preferred embodiment, the sealing members 2455 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke length.

The lower sealing head 2340 may be coupled to the load mandrel 2345 using
25 any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the lower sealing head 2340 is removably coupled to the load mandrel 2345 by a standard threaded connection. In a preferred
30 embodiment, the mechanical coupling between the lower sealing head 2340 and the load mandrel 2345 includes one or more sealing members 2460 for fluidically sealing the interface between the lower sealing head 2340 and the load mandrel

2345. The sealing members 2460 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2460 comprise polypak seals available from Parker Seals in order to
5 optimally provide sealing for a long axial stroke length.

In a preferred embodiment, the lower sealing head 2340 includes a throat passage 2465 fluidically coupled between the fluid passages 2405 and 2415. The throat passage 2465 is preferably of reduced size and is adapted to receive and engage with a plug 2470, or other similar device. In this manner, the fluid passage
10 2405 is fluidically isolated from the fluid passage 2415. In this manner, the pressure chamber 2475 is pressurized.

The outer sealing mandrel 2350 is coupled to the upper sealing head 2335 and the expansion cone 2355. The outer sealing mandrel 2350 is also movably coupled to the inner surface of the casing 2375 and the outer surface of the lower
15 sealing head 2340. In this manner, the upper sealing head 2335, outer sealing mandrel 2350, and the expansion cone 2355 reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel 2350 and the inner surface of the casing 2375 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer
20 surface of the outer sealing mandrel 2350 and the inner surface of the casing 2375 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2355 during the expansion process. The radial clearance between the inner surface of the outer sealing mandrel 2350 and the outer surface of the lower sealing head 2340 may range, for example, from about 0.0025 to 0.375
25 inches. In a preferred embodiment, the radial clearance between the inner surface of the outer sealing mandrel 2350 and the outer surface of the lower sealing head 2340 ranges from about 0.005 to 0.010 inches in order to optimally provide minimal clearance.

The outer sealing mandrel 2350 preferably comprises an annular member
30 having substantially cylindrical inner and outer surfaces. The outer sealing mandrel 2350 may be fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel

or other similar high strength materials. In a preferred embodiment, the outer sealing mandrel 2350 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel 2350 may be coupled to the upper sealing head
5 2335 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty threaded connections, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2350 is removably coupled to the upper sealing head 2335 by a standard threaded
10 connection. The outer sealing mandrel 2350 may be coupled to the expansion cone 2355 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2350
15 is removably coupled to the expansion cone 2355 by a standard threaded connection.

The upper sealing head 2335, the lower sealing head 2340, the inner sealing mandrel 2330, and the outer sealing mandrel 2350 together define a pressure chamber 2475. The pressure chamber 2475 is fluidically coupled to the passage 2405
20 via one or more passages 2410. During operation of the apparatus 2300, the plug 2470 engages with the throat passage 2465 to fluidically isolate the fluid passage 2415 from the fluid passage 2405. The pressure chamber 2475 is then pressurized which in turn causes the upper sealing head 2335, outer sealing mandrel 2350, and expansion cone 2355 to reciprocate in the axial direction. The axial motion of the
25 expansion cone 2355 in turn expands the casing 2375 in the radial direction.

The load mandrel 2345 is coupled to the lower sealing head 2340 and the mechanical slip body 2360. The load mandrel 2345 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 2345 may be fabricated from any number of conventional
30 commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 2345 is fabricated from

stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 2345 may be coupled to the lower sealing head 2340 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the load mandrel 2345 is removably coupled to the lower sealing head 2340 by a standard threaded connection. The load mandrel 2345 may be coupled to the mechanical slip body 2360 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the load mandrel 2345 is removably coupled to the mechanical slip body 2360 by a standard threaded connection.

The load mandrel 2345 preferably includes a fluid passage 2415 that is adapted to convey fluidic materials from the fluid passage 2405 to the region outside of the apparatus 2300. In a preferred embodiment, the fluid passage 2415 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 2355 is coupled to the outer sealing mandrel 2350. The expansion cone 2355 is also movably coupled to the inner surface of the casing 2375. In this manner, the upper sealing head 2335, outer sealing mandrel 2350, and the expansion cone 2355 reciprocate in the axial direction. The reciprocation of the expansion cone 2355 causes the casing 2375 to expand in the radial direction.

The expansion cone 2355 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide radial expansion of the typical casings. The axial length of the expansion cone 2355 may range, for

example, from about 2 to 8 times the largest outside diameter of the expansion cone 2355. In a preferred embodiment, the axial length of the expansion cone 2355 ranges from about 3 to 5 times the largest outside diameter of the expansion cone 2355 in order to optimally provide stability and centralization of the expansion
5 cone 2355 during the expansion process. In a preferred embodiment, the angle of attack of the expansion cone 2355 ranges from about 5 to 30 degrees in order to optimally frictional forces with radial expansion forces. The optimum angle of attack of the expansion cone 2355 will vary as a function of the operating parameters of the particular expansion operation.

10 The expansion cone 2355 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high strength materials. In a preferred embodiment, the expansion cone 2355 is fabricated from D2 machine tool steel in order to optimally provide high strength,
15 abrasion resistance, and galling resistance. In a particularly preferred embodiment, the outside surface of the expansion cone 2355 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength, abrasion resistance, resistance to galling.

The expansion cone 2355 may be coupled to the outside sealing mandrel
20 2350 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the expansion cone 2355 is coupled to the outside sealing mandrel 2350 using a standard threaded connection
25 in order to optimally provide high strength and permit the expansion cone 2355 to be easily replaced.

The mandrel launcher 2480 is coupled to the casing 2375. The mandrel launcher 2480 comprises a tubular section of casing having a reduced wall thickness compared to the casing 2375. In a preferred embodiment, the wall
30 thickness of the mandrel launcher 2480 is about 50 to 100 % of the wall thickness of the casing 2375. In this manner, the initiation of the radial expansion of the

casing 2375 is facilitated, and the placement of the apparatus 2300 into a wellbore casing and wellbore is facilitated.

The mandrel launcher 2480 may be coupled to the casing 2375 using any number of conventional mechanical couplings. The mandrel launcher 2480 may
5 have a wall thickness ranging, for example, from about 0.15 to 1.5 inches. In a preferred embodiment, the wall thickness of the mandrel launcher 2480 ranges from about 0.25 to 0.75 inches in order to optimally provide high strength in a minimal profile. The mandrel launcher 2480 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield
10 tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the mandrel launcher 2480 is fabricated from oilfield tubular goods having a higher strength than that of the casing 2375 but with a smaller wall thickness than the casing 2375 in order to optimally provide a thin walled container having approximately the same burst
15 strength as that of the casing 2375.

The mechanical slip body 2460 is coupled to the load mandrel 2345, the mechanical slips 2365, and the drag blocks 2370. The mechanical slip body 2460 preferably comprises a tubular member having an inner passage 2485 fluidically coupled to the passage 2415. In this manner, fluidic materials may be conveyed
20 from the passage 2484 to a region outside of the apparatus 2300.

The mechanical slip body 2360 may be coupled to the load mandrel 2345 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2360 is removably coupled to the load mandrel 2345 using threads and sliding steel retaining rings in order to optimally
25 provide a high strength attachment. The mechanical slip body 2360 may be coupled to the mechanical slips 2365 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2360 is removably coupled to the mechanical slips 2365 using threads and sliding steel retaining rings in order to optimally provide a high strength attachment. The mechanical slip
30 body 2360 may be coupled to the drag blocks 2370 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2360 is removably coupled to the drag blocks 2365 using threads and

sliding steel retaining rings in order to optimally provide a high strength attachment.

The mechanical slips 2365 are coupled to the outside surface of the mechanical slip body 2360. During operation of the apparatus 2300, the
5 mechanical slips 2365 prevent upward movement of the casing 2375 and mandrel launcher 2480. In this manner, during the axial reciprocation of the expansion cone 2355, the casing 2375 and mandrel launcher 2480 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2480 and casing 2375 are expanded in the radial direction by the axial movement of the
10 expansion cone 2355.

The mechanical slips 2365 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a
15 preferred embodiment, the mechanical slips 2365 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2375 during the expansion process.

The drag blocks 2370 are coupled to the outside surface of the mechanical
20 slip body 2360. During operation of the apparatus 2300, the drag blocks 2370 prevent upward movement of the casing 2375 and mandrel launcher 2480. In this manner, during the axial reciprocation of the expansion cone 2355, the casing 2375 and mandrel launcher 2480 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2480 and casing 2375 are expanded in the
25 radial direction by the axial movement of the expansion cone 2355.

The drag blocks 2370 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer mechanical drag blocks or Model 3L retrievable bridge plug drag blocks. In a preferred embodiment, the drag blocks 2370 comprise RTTS packer mechanical
30 drag blocks available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2375 during the expansion process.

The casing 2375 is coupled to the mandrel launcher 2480. The casing 2375 is further removably coupled to the mechanical slips 2365 and drag blocks 2370. The casing 2375 preferably comprises a tubular member. The casing 2375 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oil country tubular goods, carbon steel, low alloy steel, stainless steel or other similar high strength materials. In a preferred embodiment, the casing 2375 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength. In a preferred embodiment, the upper end of the casing 2375 includes one or more sealing members positioned about the exterior of the casing 2375.

During operation, the apparatus 2300 is positioned in a wellbore with the upper end of the casing 2375 positioned in an overlapping relationship within an existing wellbore casing. In order minimize surge pressures within the borehole during placement of the apparatus 2300, the fluid passage 2380 is preferably provided with one or more pressure relief passages. During the placement of the apparatus 2300 in the wellbore, the casing 2375 is supported by the expansion cone 2355.

After positioning of the apparatus 2300 within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic material is pumped into the fluid passage 2380 from a surface location. The first fluidic material is conveyed from the fluid passage 2380 to the fluid passages 2385, 2390, 2395, 2405, 2415, and 2485. The first fluidic material will then exit the apparatus 2300 and fill the annular region between the outside of the apparatus 2300 and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional commercially available materials such as, for example, epoxy, drilling mud, slag mix, cement, or water. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, slag mix, epoxy, or cement. In this manner, a wellbore casing having an outer annular layer of a hardenable material may be formed.

The first fluidic material may be pumped into the apparatus 2300 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi, and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the apparatus 2300 at operating pressures and flow rates
5 ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus 2300 has been filled to a predetermined level, a plug 2470, dart, or other similar device is
10 introduced into the first fluidic material. The plug 2470 lodges in the throat passage 2465 thereby fluidically isolating the fluid passage 2405 from the fluid passage 2415.

After placement of the plug 2470 in the throat passage 2465, a second fluidic material is pumped into the fluid passage 2380 in order to pressurize the pressure
15 chamber 2475. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricants. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant.

20 The second fluidic material may be pumped into the apparatus 2300 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the apparatus 2300 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to
25 optimally provide operational efficiency.

The pressurization of the pressure chamber 2475 causes the upper sealing head 2335, outer sealing mandrel 2350, and expansion cone 2355 to move in an axial direction. The pressurization of the pressure chamber 2475 also causes the hydraulic slips 2325 to expand in the radial direction and hold the casing 2375 in
30 a substantially stationary position. Furthermore, as the expansion cone 2355 moves in the axial direction, the expansion cone 2355 pulls the mandrel launcher 2480 and drag blocks 2370 along, which sets the mechanical slips 2365 and stops

further axial movement of the mandrel launcher 2480 and casing 2375. In this manner, the axial movement of the expansion cone 2355 radially expands the mandrel launcher 2480 and casing 2375.

Once the upper sealing head 2335, outer sealing mandrel 2350, and
5 expansion cone 2355 complete an axial stroke, the operating pressure of the second fluidic material is reduced. The reduction in the operating pressure of the second fluidic material releases the hydraulic slips 2325. The drill string 2305 is then raised. This causes the inner sealing mandrel 2330, lower sealing head 2340, load mandrel 2345, and mechanical slip body 2360 to move upward. This unsets the
10 mechanical slips 2365 and permits the mechanical slips 2365 and drag blocks 2370 to be moved within the mandrel launcher 2480 and casing 2375. When the lower sealing head 2340 contacts the upper sealing head 2335, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher 2480 and casing 2375 are radial expanded through repeated
15 axial strokes of the upper sealing head 2335, outer sealing mandrel 2350 and expansion cone 2355. Throughout the radial expansion process, the upper end of the casing 2375 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 2375
20 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the sealing members provided at the upper end of the casing 2375 provide a fluidic seal between the outside surface of the upper end of the casing 2375 and the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the contact
25 pressure between the casing 2375 and the existing section of wellbore casing ranges from about 400 to 10,000 psi in order to optimally provide contact pressure, activate the sealing members, and withstand typical tensile and compressive loading conditions.

In a preferred embodiment, as the expansion cone 2355 nears the upper end
30 of the casing 2375, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus 2300. In an alternative embodiment,

the apparatus 2300 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2375.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2355
5 nears the end of the casing 2375 in order to optimally provide reduced axial movement and velocity of the expansion cone 2355. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2300 to the range of about 0 to 500 psi in order minimize
10 the resistance to the movement of the expansion cone 2355 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 2300 ranges from about 10 to 45 feet in order to optimally provide equipment that can be handled by typical oil well rigging equipment and minimize the frequency at which the expansion cone 2355 must be stopped to permit the apparatus 2300 to be re-stroked.

15 In an alternative embodiment, at least a portion of the upper sealing head 2335 includes an expansion cone for radially expanding the mandrel launcher 2480 and casing 2375 during operation of the apparatus 2300 in order to increase the surface area of the casing 2375 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

20 In an alternative embodiment, mechanical slips 2365 are positioned in an axial location between the sealing sleeve 2315 and the inner sealing mandrel 2330 in order to optimally the construction and operation of the apparatus 2300.

Upon the complete radial expansion of the casing 2375, if applicable, the first fluidic material is permitted to cure within the annular region between the
25 outside of the expanded casing 2375 and the interior walls of the wellbore. In the case where the casing 2375 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2375. In this manner, a new section of wellbore casing is formed within a wellbore. Alternatively, the apparatus 2300 may be used to join a first section of pipeline to an existing section of pipeline.
30 Alternatively, the apparatus 2300 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable

material. Alternatively, the apparatus 2300 may be used to expand a tubular support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus 2300 are limited to the fluid passages 2380, 2385, 2390, 2395, 2400, 2405, and 2410, and the pressure chamber 2475. No fluid pressure acts directly on the mandrel launcher 2480 and casing 2375. This permits the use of operating pressures higher than the mandrel launcher 2480 and casing 2375 could normally withstand.

Referring now to Figure 18, a preferred embodiment of an apparatus 2500 for forming a mono-diameter wellbore casing will be described. The apparatus 2500 preferably includes a drillpipe 2505, an innerstring adapter 2510, a sealing sleeve 2515, a hydraulic slip body 2520, hydraulic slips 2525, an inner sealing mandrel 2530, upper sealing head 2535, lower sealing head 2540, outer sealing mandrel 2545, load mandrel 2550, expansion cone 2555, casing 2560, and fluid passages 2565, 2570, 2575, 2580, 2585, 2590, 2595, and 2600.

The drillpipe 2505 is coupled to the innerstring adapter 2510. During operation of the apparatus 2500, the drillpipe 2505 supports the apparatus 2500. The drillpipe 2505 preferably comprises a substantially hollow tubular member or members. The drillpipe 2505 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the drillpipe 2505 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 2500 in non-vertical wellbores. The drillpipe 2505 may be coupled to the innerstring adapter 2510 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 2505 is removably coupled to the innerstring adapter 2510 by a drillpipe connection. a drillpipe connection provides the advantages of high strength and easy disassembly.

The drillpipe 2505 preferably includes a fluid passage 2565 that is adapted to convey fluidic materials from a surface location into the fluid passage 2570. In

a preferred embodiment, the fluid passage 2565 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

5 The innerstring adapter 2510 is coupled to the drill string 2505 and the sealing sleeve 2515. The innerstring adapter 2510 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2510 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel,
10 carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the innerstring adapter 2510 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

 The innerstring adapter 2510 may be coupled to the drill string 2505 using
15 any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2510 is removably coupled to the drill pipe 2505 by a drillpipe connection. The innerstring adapter 2510 may be coupled to
20 the sealing sleeve 2515 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2510 is removably coupled to the sealing sleeve 2515 by a
25 standard threaded connection.

 The innerstring adapter 2510 preferably includes a fluid passage 2570 that is adapted to convey fluidic materials from the fluid passage 2565 into the fluid passage 2575. In a preferred embodiment, the fluid passage 2570 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud
30 or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 2515 is coupled to the innerstring adapter 2510 and the hydraulic slip body 2520. The sealing sleeve 2515 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 2515 may be fabricated from any number of conventional commercially available materials
5 such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 2515 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low-friction surfaces.

The sealing sleeve 2515 may be coupled to the innerstring adapter 2510
10 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2515 is removably coupled to the innerstring adapter 2510 by a standard threaded
15 connection. The sealing sleeve 2515 may be coupled to the hydraulic slip body 2520 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2515
20 is removably coupled to the hydraulic slip body 2520 by a standard threaded connection.

The sealing sleeve 2515 preferably includes a fluid passage 2575 that is adapted to convey fluidic materials from the fluid passage 2570 into the fluid passage 2580. In a preferred embodiment, the fluid passage 2575 is adapted to
25 convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slip body 2520 is coupled to the sealing sleeve 2515, the hydraulic slips 2525, and the inner sealing mandrel 2530. The hydraulic slip body
30 2520 preferably comprises a substantially hollow tubular member or members. The hydraulic slip body 2520 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular

goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the hydraulic slip body 2520 is fabricated from carbon steel in order to optimally provide high strength.

The hydraulic slip body 2520 may be coupled to the sealing sleeve 2515
5 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2520 is removably coupled to the sealing sleeve 2515 by a standard threaded connection.

10 The hydraulic slip body 2520 may be coupled to the slips 2525 using any number of conventional commercially available mechanical couplings such as, for example, threaded connection or welding. In a preferred embodiment, the hydraulic slip body 2520 is removably coupled to the slips 2525 by a threaded connection. The hydraulic slip body 2520 may be coupled to the inner sealing mandrel 2530 using
15 any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2520 is removably coupled to the inner sealing mandrel 2530 by a standard threaded connection.

20 The hydraulic slips body 2520 preferably includes a fluid passage 2580 that is adapted to convey fluidic materials from the fluid passage 2575 into the fluid passage 2590. In a preferred embodiment, the fluid passage 2580 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000
25 psi and 0 to 3,000 gallons/minute.

The hydraulic slips body 2520 preferably includes fluid passages 2585 that are adapted to convey fluidic materials from the fluid passage 2580 into the pressure chambers of the hydraulic slips 2525. In this manner, the slips 2525 are activated upon the pressurization of the fluid passage 2580 into contact with the
30 inside surface of the casing 2560. In a preferred embodiment, the fluid passages 2585 are adapted to convey fluidic materials such as, for example, water, drilling

mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips 2525 are coupled to the outside surface of the hydraulic slip body 2520. During operation of the apparatus 2500, the slips 2525 are activated upon
5 the pressurization of the fluid passage 2580 into contact with the inside surface of the casing 2560. In this manner, the slips 2525 maintain the casing 2560 in a substantially stationary position.

The slips 2525 preferably include the fluid passages 2585, the pressure chambers 2605, spring bias 2610, and slip members 2615. The slips 2525 may
10 comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In a preferred embodiment, the slips 2525 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial
15 movement of the casing 2560 during the expansion process.

The inner sealing mandrel 2530 is coupled to the hydraulic slip body 2520 and the lower sealing head 2540. The inner sealing mandrel 2530 preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel 2530 may be fabricated from any number of conventional commercially
20 available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the inner sealing mandrel 2530 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

25 The inner sealing mandrel 2530 may be coupled to the hydraulic slip body 2520 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2530
30 is removably coupled to the hydraulic slip body 2520 by a standard threaded connection. The inner sealing mandrel 2530 may be coupled to the lower sealing head 2540 using any number of conventional commercially available mechanical

couplings such as, for example, oilfield country tubular goods specialty type threaded connection, drillpipe connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2530 is removably coupled to the lower sealing head 2540 by a standard threaded connection.

The inner sealing mandrel 2530 preferably includes a fluid passage 2590 that is adapted to convey fluidic materials from the fluid passage 2580 into the fluid passage 2600. In a preferred embodiment, the fluid passage 2590 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The upper sealing head 2535 is coupled to the outer sealing mandrel 2545 and expansion cone 2555. The upper sealing head 2535 is also movably coupled to the outer surface of the inner sealing mandrel 2530 and the inner surface of the casing 2560. In this manner, the upper sealing head 2535 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head 2535 and the outer surface of the inner sealing mandrel 2530 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 2535 and the outer surface of the inner sealing mandrel 2530 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the upper sealing head 2535 and the inner surface of the casing 2560 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 2535 and the inner surface of the casing 2560 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2535 during the expansion process.

The upper sealing head 2535 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 2535 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel,

sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555 reciprocate in the axial direction.

The radial clearance between the outer surface of the lower sealing head 2540 and the inner surface of the outer sealing mandrel 2545 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the lower sealing head 2540 and the inner surface of the outer sealing mandrel 2545 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The lower sealing head 2540 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head 2540 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the lower sealing head 2540 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the lower sealing head 2540 preferably includes one or more annular sealing members 2635 for sealing the interface between the lower sealing head 2540 and the outer sealing mandrel 2545. The sealing members 2635 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2635 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2540 may be coupled to the inner sealing mandrel 2530 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the lower sealing head 2540 is removably coupled to the inner sealing mandrel 2530 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2540 and the inner sealing mandrel 2530 includes one or more sealing members 2640 for fluidically sealing the interface between the lower sealing head 2540 and the inner sealing mandrel 2530.

The sealing members 2640 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2640 comprise polypak seals available from Parker Seals in order to
5 optimally provide sealing for a long axial stroke.

The lower sealing head 2540 may be coupled to the load mandrel 2550 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded
10 connection. In a preferred embodiment, the lower sealing head 2540 is removably coupled to the load mandrel 2550 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2540 and the load mandrel 2550 includes one or more sealing members 2645 for fluidically sealing the interface between the lower sealing head 2540 and the load
15 mandrel 2550. The sealing members 2645 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2645 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

20 In a preferred embodiment, the lower sealing head 2540 includes a throat passage 2650 fluidically coupled between the fluid passages 2590 and 2600. The throat passage 2650 is preferably of reduced size and is adapted to receive and engage with a plug 2655, or other similar device. In this manner, the fluid passage 2590 is fluidically isolated from the fluid passage 2600. In this manner, the pressure
25 chamber 2660 is pressurized.

The outer sealing mandrel 2545 is coupled to the upper sealing head 2535 and the expansion cone 2555. The outer sealing mandrel 2545 is also movably coupled to the inner surface of the casing 2560 and the outer surface of the lower sealing head 2540. In this manner, the upper sealing head 2535, outer sealing
30 mandrel 2545, and the expansion cone 2555 reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel 2545 and the inner surface of the casing 2560 may range, for example, from about 0.025 to

0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the outer sealing mandrel 2545 and the inner surface of the casing 2560 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2535 during the expansion process. The radial clearance
5 between the inner surface of the outer sealing mandrel 2545 and the outer surface of the lower sealing head 2540 may range, for example, from about 0.005 to 0.01 inches. In a preferred embodiment, the radial clearance between the inner surface of the outer sealing mandrel 2545 and the outer surface of the lower sealing head 2540 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal
10 radial clearance.

The outer sealing mandrel 2545 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel 2545 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy
15 steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the outer sealing mandrel 2545 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel 2545 may be coupled to the upper sealing head
20 2535 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2545 is removably coupled to the upper sealing head 2535 by a standard threaded
25 connection. The outer sealing mandrel 2545 may be coupled to the expansion cone 2555 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2545
30 is removably coupled to the expansion cone 2555 by a standard threaded connection.

The upper sealing head 2535, the lower sealing head 2540, the inner sealing mandrel 2530, and the outer sealing mandrel 2545 together define a pressure chamber 2660. The pressure chamber 2660 is fluidically coupled to the passage 2590 via one or more passages 2595. During operation of the apparatus 2500, the plug 2655 engages with the throat passage 2650 to fluidically isolate the fluid passage 2590 from the fluid passage 2600. The pressure chamber 2660 is then pressurized which in turn causes the upper sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555 to reciprocate in the axial direction. The axial motion of the expansion cone 2555 in turn expands the casing 2560 in the radial direction.

10 The load mandrel 2550 is coupled to the lower sealing head 2540. The load mandrel 2550 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 2550 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel
15 or other similar high strength materials. In a preferred embodiment, the load mandrel 2550 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 2550 may be coupled to the lower sealing head 2540 using any number of conventional commercially available mechanical couplings such as,
20 for example, oilfield country tubular goods, drillpipe connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the load mandrel 2550 is removably coupled to the lower sealing head 2540 by a standard threaded connection.

The load mandrel 2550 preferably includes a fluid passage 2600 that is
25 adapted to convey fluidic materials from the fluid passage 2590 to the region outside of the apparatus 2500. In a preferred embodiment, the fluid passage 2600 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

30 The expansion cone 2555 is coupled to the outer sealing mandrel 2545. The expansion cone 2555 is also movably coupled to the inner surface of the casing 2560. In this manner, the upper sealing head 2535, outer sealing mandrel 2545,

and the expansion cone 2555 reciprocate in the axial direction. The reciprocation of the expansion cone 2555 causes the casing 2560 to expand in the radial direction.

The expansion cone 2555 preferably comprises an annular member having
5 substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 in order to optimally provide radial expansion for the widest variety of tubular casings. The axial length of the expansion cone 2555 may range,
10 for example, from about 2 to 8 times the largest outside diameter of the expansion cone 2535. In a preferred embodiment, the axial length of the expansion cone 2535 ranges from about 3 to 5 times the largest outside diameter of the expansion cone 2535 in order to optimally provide stabilization and centralization of the expansion cone 2535 during the expansion process. In a particularly preferred embodiment,
15 the maximum outside diameter of the expansion cone 2555 is between about 95 to 99 % of the inside diameter of the existing wellbore that the casing 2560 will be joined with. In a preferred embodiment, the angle of attack of the expansion cone 2555 ranges from about 5 to 30 degrees in order to optimally balance frictional forces and radial expansion forces. The optimum angle of attack of the expansion
20 cone 2535 will vary as a function of the particular operational features of the expansion operation.

The expansion cone 2555 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high
25 strength materials. In a preferred embodiment, the expansion cone 2555 is fabricated from D2 machine tool steel in order to optimally provide high strength, and resistance to wear and galling. In a particularly preferred embodiment, the outside surface of the expansion cone 2555 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and wear
30 resistance.

The expansion cone 2555 may be coupled to the outside sealing mandrel 2545 using any number of conventional commercially available mechanical

couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the expansion cone 2555 is coupled to the outside sealing mandrel 2545 using a standard threaded connection in order to
5 optimally provide high strength and easy replacement of the expansion cone 2555.

The casing 2560 is removably coupled to the slips 2525 and expansion cone 2555. The casing 2560 preferably comprises a tubular member. The casing 2560 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, low
10 alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the casing 2560 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength using standardized materials.

In a preferred embodiment, the upper end 2665 of the casing 2560 includes
15 a thin wall section 2670 and an outer annular sealing member 2675. In a preferred embodiment, the wall thickness of the thin wall section 2670 is about 50 to 100 % of the regular wall thickness of the casing 2560. In this manner, the upper end 2665 of the casing 2560 may be easily radially expanded and deformed into intimate contact with the lower end of an existing section of wellbore casing. In
20 a preferred embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section 2670 of casing 2560 into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

25 The annular sealing member 2675 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal, or plastic. In a preferred embodiment, the annular sealing member 2675 is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the annular
30 sealing member 2675 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the wellbore casing that the casing 2560 is joined to. In this manner, after radial expansion, the annular sealing member 2670

optimally provides a fluidic seal and also preferably optimally provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing 2560 to support the casing 2560.

In a preferred embodiment, the lower end 2680 of the casing 2560 includes
5 a thin wall section 2685 and an outer annular sealing member 2690. In a preferred embodiment, the wall thickness of the thin wall section 2685 is about 50 to 100 % of the regular wall thickness of the casing 2560. In this manner, the lower end 2680 of the casing 2560 may be easily expanded and deformed. Furthermore, in this manner, an other section of casing may be easily joined with the lower end
10 2680 of the casing 2560 using a radial expansion process. In a preferred embodiment, the upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section of the upper end of the other casing into the thin walled section 2685 of the lower end 2680 of the casing 2560 results in a wellbore casing having a substantially constant
15 inside diameter.

The annular sealing member 2690 may be fabricated from any number of conventional commercially available sealing materials such as, for example, rubber, metal, plastic or epoxy. In a preferred embodiment, the annular sealing member 2690 is fabricated from StrataLock epoxy in order to optimally provide
20 compressibility and resistance to wear. The outside diameter of the annular sealing member 2690 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 2560 is joined to. In this manner, after radial expansion, the annular sealing member 2690 preferably provides a fluidic seal and also preferably provides sufficient
25 frictional force with the inside wall of the wellbore during the radial expansion of the casing 2560 to support the casing 2560.

During operation, the apparatus 2500 is preferably positioned in a wellbore with the upper end 2665 of the casing 2560 positioned in an overlapping relationship with the lower end of an existing wellbore casing. In a particularly
30 preferred embodiment, the thin wall section 2670 of the casing 2560 is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this

manner, the radial expansion of the casing 2560 will compress the thin wall sections and annular compressible members of the upper end 2665 of the casing 2560 and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus 2500 in the wellbore, the casing 2560 is
5 supported by the expansion cone 2555.

After positioning of the apparatus 2500, a first fluidic material is then pumped into the fluid passage 2565. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, cement, water, slag-mix, epoxy or drilling mud. In a preferred embodiment, the
10 first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement, epoxy, or slag-mix in order to optimally provide a hardenable outer annular body around the expanded casing 2560.

The first fluidic material may be pumped into the fluid passage 2565 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi
15 and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the fluid passage 2565 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The first fluidic material pumped into the fluid passage 2565 passes through
20 the fluid passages 2570, 2575, 2580, 2590, 2600 and then outside of the apparatus 2500. The first fluidic material then preferably fills the annular region between the outside of the apparatus 2500 and the interior walls of the wellbore.

The plug 2655 is then introduced into the fluid passage 2565. The plug 2655 lodges in the throat passage 2650 and fluidically isolates and blocks off the fluid
25 passage 2590. In a preferred embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage 2565 in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

A second fluidic material is then pumped into the fluid passage 2565. The
30 second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In a preferred embodiment, the second fluidic material comprises a non-

hardenable fluidic material such as, for example, water, drilling mud, or lubricant in order to optimally provide pressurization of the pressure chamber 2660 and minimize friction.

5 The second fluidic material may be pumped into the fluid passage 2565 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the fluid passage 2565 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

10 The second fluidic material pumped into the fluid passage 2565 passes through the fluid passages 2570, 2575, 2580, 2590 and into the pressure chambers 2605 of the slips 2525, and into the pressure chamber 2660. Continued pumping of the second fluidic material pressurizes the pressure chambers 2605 and 2660.

15 The pressurization of the pressure chambers 2605 causes the slip members 2525 to expand in the radial direction and grip the interior surface of the casing 2560. The casing 2560 is then preferably maintained in a substantially stationary position.

The pressurization of the pressure chamber 2660 causes the upper sealing head 2535, outer sealing mandrel 2545 and expansion cone 2555 to move in an axial direction relative to the casing 2560. In this manner, the expansion cone 2555 will cause the casing 2560 to expand in the radial direction, beginning with the lower end 2685 of the casing 2560.

20 During the radial expansion process, the casing 2560 is prevented from moving in an upward direction by the slips 2525. A length of the casing 2560 is then expanded in the radial direction through the pressurization of the pressure chamber 2660. The length of the casing 2560 that is expanded during the expansion process will be proportional to the stroke length of the upper sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555.

25 Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the upper sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555 drop to their rest positions with the casing 2560 supported by the expansion cone 2555. The position of the drillpipe 2505 is

preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing 2560. In a preferred embodiment, the stroking of the expansion cone 2555 is then repeated, as
5 necessary, until the thin walled section 2670 of the upper end 2665 of the casing 2560 is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore
10 casing thousands of feet in length having a substantially constant inside diameter.

In a preferred embodiment, during the final stroke of the expansion cone 2555, the slips 2525 are positioned as close as possible to the thin walled section 2670 of the upper end 2665 of the casing 2560 in order minimize slippage between the casing 2560 and the existing wellbore casing at the end of the radial expansion
15 process. Alternatively, or in addition, the outside diameter of the annular sealing member 2675 is selected to ensure sufficient interference fit with the inside diameter of the lower end of the existing casing to prevent axial displacement of the casing 2560 during the final stroke. Alternatively, or in addition, the outside diameter of the annular sealing member 2690 is selected to provide an interference
20 fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further axial displacement of the casing 2560. In this final alternative, the interference fit is preferably selected to permit expansion of the casing 2560 by pulling the expansion cone 2555 out of the wellbore, without having to pressurize the pressure chamber 2660.

25 During the radial expansion process, the pressurized areas of the apparatus 2500 are preferably limited to the fluid passages 2565, 2570, 2575, 2580, and 2590, the pressure chambers 2605 within the slips 2525, and the pressure chamber 2660. No fluid pressure acts directly on the casing 2560. This permits the use of operating pressures higher than the casing 2560 could normally withstand.

30 Once the casing 2560 has been completely expanded off of the expansion cone 2555, the remaining portions of the apparatus 2500 are removed from the

wellbore. In a preferred embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end 2665 of the casing 2560 ranges from about 400 to 10,000 psi in order to optimally support the casing 2560 using the existing
5 wellbore casing.

In this manner, the casing 2560 is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages 2565, 2570, 2575, 2580, and 2590, the pressure chambers of the slips 2605 and the pressure chamber 2660 of the apparatus 2500.

10 In a preferred embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing 2560. In the case where the casing 2560 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2560. The resulting new section of wellbore casing includes the expanded casing 2560 and the
15 rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing 2560 includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular
20 members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In a preferred embodiment, as the expansion cone 2555 nears the upper end
25 2665 of the casing 2560, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus 2500. In an alternative embodiment, the apparatus 2500 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2560.

In a preferred embodiment, the reduced operating pressure of the second
30 fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2555 nears the end of the casing 2560 in order to optimally provide reduced axial movement and velocity of the expansion cone 2555. In a preferred embodiment,

the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2500 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 2555 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 2500 ranges
5 from about 10 to 45 feet in order to optimally provide equipments lengths that can be easily handled using typical oil well rigging equipment and also minimize the frequency at which apparatus 2500 must be re-stroked.

In an alternative embodiment, at least a portion of the upper sealing head 2535 includes an expansion cone for radially expanding the casing 2560 during
10 operation of the apparatus 2500 in order to increase the surface area of the casing 2560 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

Alternatively, the apparatus 2500 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2500 may
15 be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2500 may be used to expand a tubular support member in a hole.

Referring now to Figures 19, 19a and 19b, another embodiment of an apparatus 2700 for expanding a tubular member will be described. The apparatus
20 2700 preferably includes a drillpipe 2705, an innerstring adapter 2710, a sealing sleeve 2715, a first inner sealing mandrel 2720, a first upper sealing head 2725, a first lower sealing head 2730, a first outer sealing mandrel 2735, a second inner sealing mandrel 2740, a second upper sealing head 2745, a second lower sealing head 2750, a second outer sealing mandrel 2755, a load mandrel 2760, an
25 expansion cone 2765, a mandrel launcher 2770, a mechanical slip body 2775, mechanical slips 2780, drag blocks 2785, casing 2790, and fluid passages 2795, 2800, 2805, 2810, 2815, 2820, 2825, and 2830.

The drillpipe 2705 is coupled to the innerstring adapter 2710. During operation of the apparatus 2700, the drillpipe 2705 supports the apparatus 2700.
30 The drillpipe 2705 preferably comprises a substantially hollow tubular member or members. The drillpipe 2705 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular

goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the drillpipe 2705 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 2700 in non-vertical wellbores. The drillpipe 2705 may be coupled to the innerstring adapter 2710
5 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 2705 is removably coupled to the innerstring adapter 2710 by a drillpipe connection in order to optimally provide high strength and easy
10 disassembly.

The drillpipe 2705 preferably includes a fluid passage 2795 that is adapted to convey fluidic materials from a surface location into the fluid passage 2800. In a preferred embodiment, the fluid passage 2795 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants
15 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 2710 is coupled to the drill string 2705 and the sealing sleeve 2715. The innerstring adapter 2710 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2710
20 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the innerstring adapter 2710 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction
25 surfaces.

The innerstring adapter 2710 may be coupled to the drill string 2705 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the
30 innerstring adapter 2710 is removably coupled to the drill pipe 2705 by a standard threaded connection in order to optimally provide high strength and easy disassembly. The innerstring adapter 2710 may be coupled to the sealing sleeve

2715 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the innerstring adapter
5 2710 is removably coupled to the sealing sleeve 2715 by a standard threaded connection.

The innerstring adapter 2710 preferably includes a fluid passage 2800 that is adapted to convey fluidic materials from the fluid passage 2795 into the fluid passage 2805. In a preferred embodiment, the fluid passage 2800 is adapted to
10 convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 2715 is coupled to the innerstring adapter 2710 and the first inner sealing mandrel 2720. The sealing sleeve 2715 preferably comprises a
15 substantially hollow tubular member or members. The sealing sleeve 2715 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 2715 is fabricated from stainless steel in order to
20 optimally provide high strength, corrosion resistance, and low friction surfaces.

The sealing sleeve 2715 may be coupled to the innerstring adapter 2710 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded
25 connection. In a preferred embodiment, the sealing sleeve 2715 is removably coupled to the innerstring adapter 2710 by a standard threaded connector. The sealing sleeve 2715 may be coupled to the first inner sealing mandrel 2720 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type
30 threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2715 is removably coupled to the inner sealing mandrel 2720 by a standard threaded connection.

The sealing sleeve 2715 preferably includes a fluid passage 2802 that is adapted to convey fluidic materials from the fluid passage 2800 into the fluid passage 2805. In a preferred embodiment, the fluid passage 2802 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud
5 or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 2720 is coupled to the sealing sleeve 2715 and the first lower sealing head 2730. The first inner sealing mandrel 2720 preferably comprises a substantially hollow tubular member or members. The first
10 inner sealing mandrel 2720 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first inner sealing mandrel 2720 is fabricated from stainless steel in order to optimally provide high strength,
15 corrosion resistance, and low friction surfaces.

The first inner sealing mandrel 2720 may be coupled to the sealing sleeve 2715 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard
20 threaded connection. In a preferred embodiment, the first inner sealing mandrel 2720 is removably coupled to the sealing sleeve 2715 by a standard threaded connection. The first inner sealing mandrel 2720 may be coupled to the first lower sealing head 2730 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country
25 tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 2720 is removably coupled to the first lower sealing head 2730 by a standard threaded connection.

The first inner sealing mandrel 2720 preferably includes a fluid passage
30 2805 that is adapted to convey fluidic materials from the fluid passage 2802 into the fluid passage 2810. In a preferred embodiment, the fluid passage 2805 is adapted to convey fluidic materials such as, for example, cement, epoxy, water,

drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first upper sealing head 2725 is coupled to the first outer sealing mandrel 2735, the second upper sealing head 2745, the second outer sealing
5 mandrel 2755, and the expansion cone 2765. The first upper sealing head 2725 is also movably coupled to the outer surface of the first inner sealing mandrel 2720 and the inner surface of the casing 2790. In this manner, the first upper sealing head 2725 reciprocates in the axial direction. The radial clearance between the
10 inner cylindrical surface of the first upper sealing head 2725 and the outer surface of the first inner sealing mandrel 2720 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the first upper sealing head 2725 and the outer surface of the first inner sealing mandrel 2720 ranges from about 0.005 to 0.125 inches in order to optimally provide minimal radial clearance. The radial clearance between the
15 outer cylindrical surface of the first upper sealing head 2725 and the inner surface of the casing 2790 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the first upper sealing head 2725 and the inner surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the
20 expansion cone 2765 during the expansion process.

The first upper sealing head 2725 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first upper sealing head 2725 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy
25 steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first upper sealing head 2725 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance and low friction surfaces. The inner surface of the first upper sealing head 2725 preferably includes one or more annular sealing members 2835 for sealing the
30 interface between the first upper sealing head 2725 and the first inner sealing mandrel 2720. The sealing members 2835 may comprise any number of conventional commercially available annular sealing members such as, for

example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2835 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

In a preferred embodiment, the first upper sealing head 2725 includes a
5 shoulder 2840 for supporting the first upper sealing head 2725 on the first lower sealing head 2730.

The first upper sealing head 2725 may be coupled to the first outer sealing mandrel 2735 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country
10 tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the first upper sealing head 2725 is removably coupled to the first outer sealing mandrel 2735 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first upper sealing head 2725 and the first outer sealing
15 mandrel 2735 includes one or more sealing members 2845 for fluidicly sealing the interface between the first upper sealing head 2725 and the first outer sealing mandrel 2735. The sealing members 2845 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the
20 sealing members 2845 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 is coupled to the first inner sealing mandrel 2720 and the second inner sealing mandrel 2740. The first lower sealing head 2730 is also movably coupled to the inner surface of the first outer sealing
25 mandrel 2735. In this manner, the first upper sealing head 2725 and first outer sealing mandrel 2735 reciprocate in the axial direction. The radial clearance between the outer surface of the first lower sealing head 2730 and the inner surface of the first outer sealing mandrel 2735 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between
30 the outer surface of the first lower sealing head 2730 and the inner surface of the first outer sealing mandrel 2735 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first lower sealing head 2730 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first lower sealing head 2730 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first lower sealing head 2730 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the first lower sealing head 2730 preferably includes one or more annular sealing members 2850 for sealing the interface between the first lower sealing head 2730 and the first outer sealing mandrel 2735. The sealing members 2850 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2850 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 may be coupled to the first inner sealing mandrel 2720 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connections, welding, amorphous bonding, or standard threaded connection. In a preferred embodiment, the first lower sealing head 2730 is removably coupled to the first inner sealing mandrel 2720 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first lower sealing head 2730 and the first inner sealing mandrel 2720 includes one or more sealing members 2855 for fluidically sealing the interface between the first lower sealing head 2730 and the first inner sealing mandrel 2720. The sealing members 2855 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2855 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 may be coupled to the second inner sealing mandrel 2740 using any number of conventional commercially available

mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the lower sealing head 2730 is removably coupled to the second inner sealing mandrel 2740 by a standard threaded
5 connection. In a preferred embodiment, the mechanical coupling between the first lower sealing head 2730 and the second inner sealing mandrel 2740 includes one or more sealing members 2860 for fluidically sealing the interface between the first lower sealing head 2730 and the second inner sealing mandrel 2740. The sealing members 2860 may comprise any number of conventional commercially available
10 sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2860 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first outer sealing mandrel 2735 is coupled to the first upper sealing
15 head 2725, the second upper sealing head 2745, the second outer sealing mandrel 2755, and the expansion cone 2765. The first outer sealing mandrel 2735 is also movably coupled to the inner surface of the casing 2790 and the outer surface of the first lower sealing head 2730. In this manner, the first upper sealing head 2725, first outer sealing mandrel 2735, second upper sealing head 2745, second
20 outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction. The radial clearance between the outer surface of the first outer sealing mandrel 2735 and the inner surface of the casing 2790 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the first outer sealing mandrel 2735 and the inner
25 surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2765 during the expansion process. The radial clearance between the inner surface of the first outer sealing mandrel 2735 and the outer surface of the first lower sealing head 2730 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the
30 radial clearance between the inner surface of the first outer sealing mandrel 2735 and the outer surface of the first lower sealing head 2730 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The outer sealing mandrel 1935 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first outer sealing mandrel 2735 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first outer sealing mandrel 2735 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first outer sealing mandrel 2735 may be coupled to the first upper sealing head 2725 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the first outer sealing mandrel 2735 is removably coupled to the first upper sealing head 2725 by a standard threaded connection. The first outer sealing mandrel 2735 may be coupled to the second upper sealing head 2745 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the first outer sealing mandrel 2735 is removably coupled to the second upper sealing head 2745 by a standard threaded connection.

The second inner sealing mandrel 2740 is coupled to the first lower sealing head 2730 and the second lower sealing head 2750. The second inner sealing mandrel 2740 preferably comprises a substantially hollow tubular member or members. The second inner sealing mandrel 2740 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second inner sealing mandrel 2740 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second inner sealing mandrel 2740 may be coupled to the first lower sealing head 2730 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty

threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the second inner sealing mandrel 2740 is removably coupled to the first lower sealing head 2740 by a standard threaded connection. The mechanical coupling between the second inner sealing mandrel
5 2740 and the first lower sealing head 2730 preferably includes sealing members 2860.

The second inner sealing mandrel 2740 may be coupled to the second lower sealing head 2750 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty
10 threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the second inner sealing mandrel 2720 is removably coupled to the second lower sealing head 2750 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second inner sealing mandrel 2740 and the second lower sealing head 2750
15 includes one or more sealing members 2865. The sealing members 2865 may comprise any number of conventional commercially available seals such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2865 comprise polypak seals available from Parker Seals.

20 The second inner sealing mandrel 2740 preferably includes a fluid passage 2810 that is adapted to convey fluidic materials from the fluid passage 2805 into the fluid passage 2815. In a preferred embodiment, the fluid passage 2810 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from
25 about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The second upper sealing head 2745 is coupled to the first upper sealing head 2725, the first outer sealing mandrel 2735, the second outer sealing mandrel 2755, and the expansion cone 2765. The second upper sealing head 2745 is also movably coupled to the outer surface of the second inner sealing mandrel 2740 and
30 the inner surface of the casing 2790. In this manner, the second upper sealing head 2745 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the second upper sealing head 2745 and the outer

surface of the second inner sealing mandrel 2740 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the second upper sealing head 2745 and the outer surface of the second inner sealing mandrel 2740 ranges from about
5 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the second upper sealing head 2745 and the inner surface of the casing 2790 may range, for example, from about 0.025 to .375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the second upper sealing head 2745 and
10 the inner surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2765 during the expansion process.

The second upper sealing head 2745 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second
15 upper sealing head 2745 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second upper sealing head 2745 is fabricated from stainless steel in order to optimally provide high strength,
20 corrosion resistance, and low friction surfaces. The inner surface of the second upper sealing head 2745 preferably includes one or more annular sealing members 2870 for sealing the interface between the second upper sealing head 2745 and the second inner sealing mandrel 2740. The sealing members 2870 may comprise any number of conventional commercially available annular sealing members such as;
25 for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2870 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

In a preferred embodiment, the second upper sealing head 2745 includes a shoulder 2875 for supporting the second upper sealing head 2745 on the second
30 lower sealing head 2750.

The second upper sealing head 2745 may be coupled to the first outer sealing mandrel 2735 using any number of conventional commercially available

mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second upper sealing head 2745 is removably coupled to the first outer sealing mandrel 2735 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second upper sealing head 2745 and the first outer sealing mandrel 2735 includes one or more sealing members 2880 for fluidically sealing the interface between the second upper sealing head 2745 and the first outer sealing mandrel 2735. The sealing members 2880 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2880 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second upper sealing head 2745 may be coupled to the second outer sealing mandrel 2755 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the second upper sealing head 2745 is removably coupled to the second outer sealing mandrel 2755 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second upper sealing head 2745 and the second outer sealing mandrel 2755 includes one or more sealing members 2885 for fluidically sealing the interface between the second upper sealing head 2745 and the second outer sealing mandrel 2755. The sealing members 2885 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2885 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 2750 is coupled to the second inner sealing mandrel 2740 and the load mandrel 2760. The second lower sealing head 2750 is also movably coupled to the inner surface of the second outer sealing mandrel 2755. In this manner, the first upper sealing head 2725, the first outer sealing

mandrel 2735, second upper sealing head 2745, second outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction. The radial clearance between the outer surface of the second lower sealing head 2750 and the inner surface of the second outer sealing mandrel 2755 may range, for example, 5 from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the second lower sealing head 2750 and the inner surface of the second outer sealing mandrel 2755 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second lower sealing head 2750 preferably comprises an annular 10 member having substantially cylindrical inner and outer surfaces. The second lower sealing head 2750 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second lower sealing head 2750 is 15 fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the second lower sealing head 2750 preferably includes one or more annular sealing members 2890 for sealing the interface between the second lower sealing head 2750 and the second outer sealing mandrel 2755. The sealing members 2890 may comprise any 20 number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2890 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 2750 may be coupled to the second inner 25 sealing mandrel 2740 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second lower sealing head 2750 is removably coupled to the second inner sealing 30 mandrel 2740 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second lower sealing head 2750 and the second inner sealing mandrel 2740 includes one or more sealing members 2895 for

fluidically sealing the interface between the second sealing head 2750 and the second sealing mandrel 2740. The sealing members 2895 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the
5 sealing members 2895 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second lower sealing head 2750 may be coupled to the load mandrel 2760 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield tubular goods specialty
10 threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second lower sealing head 2750 is removably coupled to the load mandrel 2760 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second lower sealing head 2750 and the load mandrel 2760 includes one or more
15 sealing members 2900 for fluidically sealing the interface between the second lower sealing head 2750 and the load mandrel 2760. The sealing members 2900 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2900 comprise polypak seals available
20 from Parker Seals in order to optimally provide sealing for long axial strokes.

In a preferred embodiment, the second lower sealing head 2750 includes a throat passage 2905 fluidically coupled between the fluid passages 2810 and 2815. The throat passage 2905 is preferably of reduced size and is adapted to receive and engage with a plug 2910, or other similar device. In this manner, the fluid passage
25 2810 is fluidically isolated from the fluid passage 2815. In this manner, the pressure chambers 2915 and 2920 are pressurized. The use of a plurality of pressure chambers in the apparatus 2700 permits the effective driving force to be multiplied. While illustrated using a pair of pressure chambers, 2915 and 2920, the apparatus 2700 may be further modified to employ additional pressure
30 chambers.

The second outer sealing mandrel 2755 is coupled to the first upper sealing head 2725, the first outer sealing mandrel 2735, the second upper sealing head

2745, and the expansion cone 2765. The second outer sealing mandrel 2755 is also movably coupled to the inner surface of the casing 2790 and the outer surface of the second lower sealing head 2750. In this manner, the first upper sealing head 2725, first outer sealing mandrel 2735, second upper sealing head 2745, second
5 outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction.

The radial clearance between the outer surface of the second outer sealing mandrel 2755 and the inner surface of the casing 2790 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance
10 between the outer surface of the second outer sealing mandrel 2755 and the inner surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2765 during the expansion process. The radial clearance between the inner surface of the second outer sealing mandrel 2755 and the outer surface of the second lower sealing head 2750 may
15 range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner surface of the second outer sealing mandrel 2755 and the outer surface of the second lower sealing head 2750 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second outer sealing mandrel 2755 preferably comprises an annular
20 member having substantially cylindrical inner and outer surfaces. The second outer sealing mandrel 2755 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second outer sealing mandrel 2755 is
25 fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second outer sealing mandrel 2755 may be coupled to the second upper sealing head 2745 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country
30 tubular goods specialty threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the second outer sealing mandrel 2755 is removably coupled to the second upper

sealing head 2745 by a standard threaded connection. The second outer sealing mandrel 2755 may be coupled to the expansion cone 2765 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded
5 connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second outer sealing mandrel 2755 is removably coupled to the expansion cone 2765 by a standard threaded connection.

The load mandrel 2760 is coupled to the second lower sealing head 2750 and the mechanical slip body 2755. The load mandrel 2760 preferably comprises an
10 annular member having substantially cylindrical inner and outer surfaces. The load mandrel 2760 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 2760 is fabricated from
15 stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 2760 may be coupled to the second lower sealing head 2750 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods
20 specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the load mandrel 2760 is removably coupled to the second lower sealing head 2750 by a standard threaded connection. The load mandrel 2760 may be coupled to the mechanical slip body 2775 using any number of conventional commercially available mechanical
25 couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the load mandrel 2760 is removably coupled to the mechanical slip body 2775 by a standard threaded connection.

30 The load mandrel 2760 preferably includes a fluid passage 2815 that is adapted to convey fluidic materials from the fluid passage 2810 to the fluid passage 2820. In a preferred embodiment, the fluid passage 2815 is adapted to convey

fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 2765 is coupled to the second outer sealing mandrel
5 2755. The expansion cone 2765 is also movably coupled to the inner surface of the casing 2790. In this manner, the first upper sealing head 2725, first outer sealing mandrel 2735, second upper sealing head 2745, second outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction. The reciprocation of the expansion cone 2765 causes the casing 2790 to expand in the radial
10 direction.

The expansion cone 2765 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges
15 from about 3 to 28 inches in order to optimally provide expansion cone dimensions that accommodate the typical range of casings. The axial length of the expansion cone 2765 may range, for example, from about 2 to 8 times the largest outer diameter of the expansion cone 2765. In a preferred embodiment, the axial length of the expansion cone 2765 ranges from about 3 to 5 times the largest outer
20 diameter of the expansion cone 2765 in order to optimally provide stabilization and centralization of the expansion cone 2765. In a preferred embodiment, the angle of attack of the expansion cone 2765 ranges from about 5 to 30 degrees in order to optimally balance frictional forces and radial expansion forces.

The expansion cone 2765 may be fabricated from any number of
25 conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high strength materials. In a preferred embodiment, the expansion cone 2765 is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to corrosion and galling. In a particularly preferred embodiment,
30 the outside surface of the expansion cone 2765 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resistance to wear and galling.

The expansion cone 2765 may be coupled to the second outside sealing mandrel 2765 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded
5 connection or a standard threaded connection. In a preferred embodiment, the expansion cone 2765 is coupled to the second outside sealing mandrel 2765 using a standard threaded connection in order to optimally provide high strength and easy replacement of the expansion cone 2765.

The mandrel launcher 2770 is coupled to the casing 2790. The mandrel
10 launcher 2770 comprises a tubular section of casing having a reduced wall thickness compared to the casing 2790. In a preferred embodiment, the wall thickness of the mandrel launcher 2770 is about 50 to 100 % of the wall thickness of the casing 2790. The wall thickness of the mandrel launcher 2770 may range, for example, from about 0.15 to 1.5 inches. In a preferred embodiment, the wall
15 thickness of the mandrel launcher 2770 ranges from about 0.25 to 0.75 inches. In this manner, the initiation of the radial expansion of the casing 2790 is facilitated, the placement of the apparatus 2700 within a wellbore casing and wellbore is facilitated, and the mandrel launcher 2770 has a burst strength approximately equal to that of the casing 2790.

20 The mandrel launcher 2770 may be coupled to the casing 2790 using any number of conventional mechanical couplings such as, for example, a standard threaded connection. The mandrel launcher 2770 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other
25 similar high strength materials. In a preferred embodiment, the mandrel launcher 2770 is fabricated from oilfield country tubular goods of higher strength than that of the casing 2790 but with a reduced wall thickness in order to optimally provide a small compact tubular container having a burst strength approximately equal to that of the casing 2790.

30 The mechanical slip body 2775 is coupled to the load mandrel 2760, the mechanical slips 2780, and the drag blocks 2785. The mechanical slip body 2775 preferably comprises a tubular member having an inner passage 2820 fluidly

coupled to the passage 2815. In this manner, fluidic materials may be conveyed from the passage 2820 to a region outside of the apparatus 2700.

The mechanical slip body 2775 may be coupled to the load mandrel 2760 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2775 is removably coupled to the load mandrel 2760 using a standard threaded connection in order to optimally provide high strength and easy disassembly. The mechanical slip body 2775 may be coupled to the mechanical slips 2780 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2755 is removably coupled to the mechanical slips 2780 using threaded connections and sliding steel retainer rings in order to optimally provide a high strength attachment. The mechanical slip body 2755 may be coupled to the drag blocks 2785 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2775 is removably coupled to the drag blocks 2785 using threaded connections and sliding steel retainer rings in order to optimally provide a high strength attachment.

The mechanical slip body 2775 preferably includes a fluid passage 2820 that is adapted to convey fluidic materials from the fluid passage 2815 to the region outside of the apparatus 2700. In a preferred embodiment, the fluid passage 2820 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The mechanical slips 2780 are coupled to the outside surface of the mechanical slip body 2775. During operation of the apparatus 2700, the mechanical slips 2780 prevent upward movement of the casing 2790 and mandrel launcher 2770. In this manner, during the axial reciprocation of the expansion cone 2765, the casing 2790 and mandrel launcher 2770 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2765 and casing 2790 and mandrel launcher 2770 are expanded in the radial direction by the axial movement of the expansion cone 2765.

The mechanical slips 2780 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer

tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the mechanical slips 2780 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to
5 optimally provide resistance to axial movement of the casing 2790 and mandrel launcher 2770 during the expansion process.

The drag blocks 2785 are coupled to the outside surface of the mechanical slip body 2775. During operation of the apparatus 2700, the drag blocks 2785 prevent upward movement of the casing 2790 and mandrel launcher 2770. In this
10 manner, during the axial reciprocation of the expansion cone 2765, the casing 2790 and mandrel launcher 2770 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2770 and casing 2790 are expanded in the radial direction by the axial movement of the expansion cone 2765.

The drag blocks 2785 may comprise any number of conventional
15 commercially available mechanical slips such as, for example, RTTS packer mechanical drag blocks or Model 3L retrievable bridge plug drag blocks. In a preferred embodiment, the drag blocks 2785 comprise RTTS packer mechanical drag blocks available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2790 and mandrel launcher
20 2770 during the expansion process.

The casing 2790 is coupled to the mandrel launcher 2770. The casing 2790 is further removably coupled to the mechanical slips 2780 and drag blocks 2785. The casing 2790 preferably comprises a tubular member. The casing 2790 may be fabricated from any number of conventional commercially available materials such
25 as, for example, slotted tubulars, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the casing 2790 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength using standardized materials. In a preferred embodiment,
30 the upper end of the casing 2790 includes one or more sealing members positioned about the exterior of the casing 2790.

During operation, the apparatus 2700 is positioned in a wellbore with the upper end of the casing 2790 positioned in an overlapping relationship within an existing wellbore casing. In order minimize surge pressures within the borehole during placement of the apparatus 2700, the fluid passage 2795 is preferably
5 provided with one or more pressure relief passages. During the placement of the apparatus 2700 in the wellbore, the casing 2790 is supported by the expansion cone 2765.

After positioning of the apparatus 2700 within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic
10 material is pumped into the fluid passage 2795 from a surface location. The first fluidic material is conveyed from the fluid passage 2795 to the fluid passages 2800, 2802, 2805, 2810, 2815, and 2820. The first fluidic material will then exit the apparatus 2700 and fill the annular region between the outside of the apparatus 2700 and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional
15 commercially available materials such as, for example, epoxy, drilling mud, slag mix, water or cement. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, slag mix, epoxy, or cement. In this manner, a wellbore casing having an outer annular layer
20 of a hardenable material may be formed.

The first fluidic material may be pumped into the apparatus 2700 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic
25 material is pumped into the apparatus 2700 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus 2700 has been filled to a predetermined level, a plug 2910, dart, or other similar device is
30 introduced into the first fluidic material. The plug 2910 lodges in the throat passage 2905 thereby fluidically isolating the fluid passage 2810 from the fluid passage 2815.

After placement of the plug 2910 in the throat passage 2905, a second fluidic material is pumped into the fluid passage 2795 in order to pressurize the pressure chambers 2915 and 2920. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, 5 drilling gases, drilling mud or lubricants. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant. The use of lubricant optimally provides lubrication of the moving parts of the apparatus 2700.

The second fluidic material may be pumped into the apparatus 2700 at 10 operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the apparatus 2700 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

15 The pressurization of the pressure chambers 2915 and 2920 cause the upper sealing heads, 2725 and 2745, outer sealing mandrels, 2735 and 2755, and expansion cone 2765 to move in an axial direction. As the expansion cone 2765 moves in the axial direction, the expansion cone 2765 pulls the mandrel launcher 2770, casing 2790, and drag blocks 2785 along, which sets the mechanical slips 20 2780 and stops further axial movement of the mandrel launcher 2770 and casing 2790. In this manner, the axial movement of the expansion cone 2765 radially expands the mandrel launcher 2770 and casing 2790.

Once the upper sealing heads, 2725 and 2745, outer sealing mandrels, 2735 and 2755, and expansion cone 2765 complete an axial stroke, the operating 25 pressure of the second fluidic material is reduced and the drill string 2705 is raised. This causes the inner sealing mandrels, 2720 and 2740, lower sealing heads, 2730 and 2750, load mandrel 2760, and mechanical slip body 2755 to move upward. This unsets the mechanical slips 2780 and permits the mechanical slips 2780 and drag blocks 2785 to be moved upward within the mandrel launcher 2770 and 30 casing 2790. When the lower sealing heads, 2730 and 2750, contact the upper sealing heads, 2725 and 2745, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher

2770 and casing 2790 are radially expanded through repeated axial strokes of the upper sealing heads, 2725 and 2745; outer sealing mandrels, 2735 and 2755, and expansion cone 2765. Throughout the radial expansion process, the upper end of the casing 2790 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 2790 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the sealing members provided at the upper end of the casing 2790 provide a fluidic seal between the outside surface of the upper end of the casing 2790 and the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the contact pressure between the casing 2790 and the existing section of wellbore casing ranges from about 400 to 10,000 in order to optimally provide contact pressure for activating the sealing members, provide optimal resistance to axial movement of the expanded casing, and optimally resist typical tensile and compressive loads on the expanded casing.

In a preferred embodiment, as the expansion cone 2765 nears the end of the casing 2790, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus 2700. In an alternative embodiment, the apparatus 2700 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2790.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2765 nears the end of the casing 2790 in order to optimally provide reduced axial movement and velocity of the expansion cone 2765. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2700 to the range of about 0 to 500 psi in order to minimize the resistance to the movement of the expansion cone 2765 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 2700 ranges from about 10 to 45 feet in order to optimally provide equipment that can be easily handled by typical oil well rigging equipment and minimize the frequency at which the apparatus 2700 must be re-stroked during an expansion operation.

In an alternative embodiment, at least a portion of the upper sealing heads, 2725 and 2745, include expansion cones for radially expanding the mandrel launcher 2770 and casing 2790 during operation of the apparatus 2700 in order to increase the surface area of the casing 2790 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

In an alternative embodiment, mechanical slips are positioned in an axial location between the sealing sleeve 1915 and the first inner sealing mandrel 2720 in order to optimally provide a simplified assembly and operation of the apparatus 2700.

10 Upon the complete radial expansion of the casing 2790, if applicable, the first fluidic material is permitted to cure within the annular region between the outside of the expanded casing 2790 and the interior walls of the wellbore. In the case where the casing 2790 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2790. In this manner, a new section
15 of wellbore casing is formed within a wellbore. Alternatively, the apparatus 2700 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2700 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2700 may be used to expand a tubular
20 support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus 2700 are limited to the fluid passages 2795, 2800, 2802, 2805, and 2810, and the pressure chambers 2915 and 2920. No fluid pressure acts directly on the mandrel launcher 2770 and casing 2790. This permits the use of operating pressures higher
25 than the mandrel launcher 2770 and casing 2790 could normally withstand.

Referring now to Figure 20, a preferred embodiment of an apparatus 3000 for forming a mono-diameter wellbore casing will be described. The apparatus 3000 preferably includes a drillpipe 3005, an innerstring adapter 3010, a sealing sleeve 3015, a first inner sealing mandrel 3020, hydraulic slips 3025, a first upper
30 sealing head 3030, a first lower sealing head 3035, a first outer sealing mandrel 3040, a second inner sealing mandrel 3045, a second upper sealing head 3050, a second lower sealing head 3055, a second outer sealing mandrel 3060, load mandrel

3065, expansion cone 3070, casing 3075, and fluid passages 3080, 3085, 3090, 3095, 3100, 3105, 3110, 3115 and 3120.

The drillpipe 3005 is coupled to the innerstring adapter 3010. During operation of the apparatus 3000, the drillpipe 3005 supports the apparatus 3000.

5 The drillpipe 3005 preferably comprises a substantially hollow tubular member or members. The drillpipe 3005 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the drillpipe 3005 is fabricated from coiled

10 tubing in order to facilitate the placement of the apparatus 3000 in non-vertical wellbores. The drillpipe 3005 may be coupled to the innerstring adapter 3010 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred

15 embodiment, the drillpipe 3005 is removably coupled to the innerstring adapter 3010 by a drillpipe connection.

The drillpipe 3005 preferably includes a fluid passage 3080 that is adapted to convey fluidic materials from a surface location into the fluid passage 3085. In a preferred embodiment, the fluid passage 3080 is adapted to convey fluidic

20 materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 3010 is coupled to the drill string 3005 and the sealing sleeve 3015. The innerstring adapter 3010 preferably comprises a

25 substantially hollow tubular member or members. The innerstring adapter 3010 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the innerstring adapter 3010 is fabricated from stainless

30 steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter 3010 may be coupled to the drill string 3005 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred
5 embodiment, the innerstring adapter 3010 is removably coupled to the drill pipe 3005 by a drillpipe connection. The innerstring adapter 3010 may be coupled to the sealing sleeve 3015 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded
10 connection or a standard threaded connection. In a preferred embodiment, the innerstring adapter 3010 is removably coupled to the sealing sleeve 3015 by a standard threaded connection.

The innerstring adapter 3010 preferably includes a fluid passage 3085 that is adapted to convey fluidic materials from the fluid passage 3080 into the fluid
15 passage 3090. In a preferred embodiment, the fluid passage 3085 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 3015 is coupled to the innerstring adapter 3010 and the
20 first inner sealing mandrel 3020. The sealing sleeve 3015 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 3015 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred
25 embodiment, the sealing sleeve 3015 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The sealing sleeve 3015 may be coupled to the innerstring adapter 3010 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty
30 type threaded connection, ratchet-latch type connection or a standard threaded connection. In a preferred embodiment, the sealing sleeve 3015 is removably coupled to the innerstring adapter 3010 by a standard threaded connection. The

sealing sleeve 3015 may be coupled to the first inner sealing mandrel 3020 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard
5 threaded connection. In a preferred embodiment, the sealing sleeve 3015 is removably coupled to the first inner sealing mandrel 3020 by a standard threaded connection.

The sealing sleeve 3015 preferably includes a fluid passage 3090 that is adapted to convey fluidic materials from the fluid passage 3085 into the fluid
10 passage 3095. In a preferred embodiment, the fluid passage 3090 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 is coupled to the sealing sleeve 3015,
15 the hydraulic slips 3025, and the first lower sealing head 3035. The first inner sealing mandrel 3020 is further movably coupled to the first upper sealing head 3030. The first inner sealing mandrel 3020 preferably comprises a substantially hollow tubular member or members. The first inner sealing mandrel 3020 may be fabricated from any number of conventional commercially available materials such
20 as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or similar high strength materials. In a preferred embodiment, the first inner sealing mandrel 3020 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first inner sealing mandrel 3020 may be coupled to the sealing sleeve
25 3015 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 3020 is removably coupled to the sealing sleeve 3015 by a standard
30 threaded connection. The first inner sealing mandrel 3020 may be coupled to the hydraulic slips 3025 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country

tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 3020 is removably coupled to the hydraulic slips 3025 by a standard threaded connection. The first inner sealing mandrel 3020 may be
5 coupled to the first lower sealing head 3035 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 3020 is removably coupled
10 to the first lower sealing head 3035 by a standard threaded connection.

The first inner sealing mandrel 3020 preferably includes a fluid passage 3095 that is adapted to convey fluidic materials from the fluid passage 3090 into the fluid passage 3100. In a preferred embodiment, the fluid passage 3095 is adapted to convey fluidic materials such as, for example, water, drilling mud,
15 cement, epoxy, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 further preferably includes fluid passages 3110 that are adapted to convey fluidic materials from the fluid passage 3095 into the pressure chambers of the hydraulic slips 3025. In this manner, the
20 slips 3025 are activated upon the pressurization of the fluid passage 3095 into contact with the inside surface of the casing 3075. In a preferred embodiment, the fluid passages 3110 are adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling fluids or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

25 The first inner sealing mandrel 3020 further preferably includes fluid passages 3115 that are adapted to convey fluidic materials from the fluid passage 3095 into the first pressure chamber 3175 defined by the first upper sealing head 3030, the first lower sealing head 3035, the first inner sealing mandrel 3020, and the first outer sealing mandrel 3040. During operation of the apparatus 3000,
30 pressurization of the pressure chamber 3175 causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the

second outer sealing mandrel 3060, and the expansion cone 3070 to move in an axial direction.

The slips 3025 are coupled to the outside surface of the first inner sealing mandrel 3020. During operation of the apparatus 3000, the slips 3025 are
5 activated upon the pressurization of the fluid passage 3095 into contact with the inside surface of the casing 3075. In this manner, the slips 3025 maintain the casing 3075 in a substantially stationary position.

The slips 3025 preferably include fluid passages 3125, pressure chambers 3130, spring bias 3135, and slip members 3140. The slips 3025 may comprise any
10 number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In a preferred embodiment, the slips 3025 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the
15 casing 3075 during the expansion process.

The first upper sealing head 3030 is coupled to the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070. The first upper sealing head 3030 is also movably coupled to the outer surface of the first inner sealing mandrel 3020
20 and the inner surface of the casing 3075. In this manner, the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction.

The radial clearance between the inner cylindrical surface of the first upper
25 sealing head 3030 and the outer surface of the first inner sealing mandrel 3020 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the first upper sealing head 3030 and the outer surface of the first inner sealing mandrel 3020 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal
30 radial clearance. The radial clearance between the outer cylindrical surface of the first upper sealing head 3030 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the

radial clearance between the outer cylindrical surface of the first upper sealing head 3030 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process.

5 The first upper sealing head 3030 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first upper sealing head 3030 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or other similar high strength materials. In a preferred
10 embodiment, the first upper sealing head 3030 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the first upper sealing head 3030 preferably includes one or more annular sealing members 3145 for sealing the interface between the first upper sealing head 3030 and the first inner sealing mandrel
15 3020. The sealing members 3145 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3145 comprise polypak seals available from Parker seals in order to optimally provide sealing for a long axial stroke.

20 In a preferred embodiment, the first upper sealing head 3030 includes a shoulder 3150 for supporting the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 on the first lower sealing head 3035. The first upper sealing head 3030 may be coupled to the first outer sealing mandrel 3040 using any
25 number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the first upper sealing head 3030 is removably coupled to the first outer sealing mandrel 3040 by a standard threaded connection. In a preferred
30 embodiment, the mechanical coupling between the first upper sealing head 3030 and the first outer sealing mandrel 3040 includes one or more sealing members 3155 for fluidically sealing the interface between the first upper sealing head 3030

and the first outer sealing mandrel 3040. The sealing members 3155 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 3155 comprise polypak seals available from
5 Parker Seals in order to optimally provide sealing for a long axial stroke.

The first lower sealing head 3035 is coupled to the first inner sealing mandrel 3020 and the second inner sealing mandrel 3045. The first lower sealing head 3035 is also movably coupled to the inner surface of the first outer sealing mandrel 3040. In this manner, the first upper sealing head 3030, first outer
10 sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the first lower sealing head 3035 and the inner surface of the first outer sealing mandrel 3040 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance
15 between the outer surface of the first lower sealing head 3035 and the inner surface of the outer sealing mandrel 3040 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first lower sealing head 3035 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first lower sealing
20 head 3035 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first lower sealing head 3035 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance,
25 and low friction surfaces. The outer surface of the first lower sealing head 3035 preferably includes one or more annular sealing members 3160 for sealing the interface between the first lower sealing head 3035 and the first outer sealing mandrel 3040. The sealing members 3160 may comprise any number of conventional commercially available annular sealing members such as, for
30 example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 3160 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first lower sealing head 3035 may be coupled to the first inner sealing mandrel 3020 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded
5 connection or a standard threaded connection. In a preferred embodiment, the first lower sealing head 3035 is removably coupled to the first inner sealing mandrel 3020 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first lower sealing head 3035 and the first inner sealing mandrel 3020 includes one or more sealing members 3165 for fluidicly
10 sealing the interface between the first lower sealing head 3035 and the first inner sealing mandrel 3020. The sealing members 3165 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 3165 comprise polypak seals available from Parker Seals in order
15 to optimally provide sealing for a long axial stroke length.

The first lower sealing head 3035 may be coupled to the second inner sealing mandrel 3045 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded
20 connection or a standard threaded connection. In a preferred embodiment, the first lower sealing head 3035 is removably coupled to the second inner sealing mandrel 3045 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first lower sealing head 3035 and the second inner sealing mandrel 3045 includes one or more sealing members 3170 for
25 fluidicly sealing the interface between the first lower sealing head 3035 and the second inner sealing mandrel 3045. The sealing members 3170 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3170 comprise polypak seals available from
30 Parker Seals in order to optimally provide sealing for a long axial stroke.

The first outer sealing mandrel 3040 is coupled to the first upper sealing head 3030 and the second upper sealing head 3050. The first outer sealing

mandrel 3040 is also movably coupled to the inner surface of the casing 3075 and the outer surface of the first lower sealing head 3035. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070
5 reciprocate in the axial direction. The radial clearance between the outer surface of the first outer sealing mandrel 3040 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the first outer sealing mandrel 3040 and the inner surface of the casing 3075 ranges from about
10 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process. The radial clearance between the inner surface of the first outer sealing mandrel 3040 and the outer surface of the first lower sealing head 3035 may range, for example, from about 0.005 to 0.125 inches. In a preferred embodiment, the radial clearance between the inner surface of the
15 first outer sealing mandrel 3040 and the outer surface of the first lower sealing head 3035 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first outer sealing mandrel 3040 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first outer
20 sealing mandrel 3040 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first outer sealing mandrel 3040 is fabricated from stainless steel in order to optimally provide high strength,
25 corrosion resistance, and low friction surfaces.

The first outer sealing mandrel 3040 may be coupled to the first upper sealing head 3030 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded
30 connection or a standard threaded connection. In a preferred embodiment, the first outer sealing mandrel 3040 is removably coupled to the first upper sealing head 3030 by a standard threaded connection. In a preferred embodiment, the

mechanical coupling between the first outer sealing mandrel 3040 and the first upper sealing head 3030 includes one or more sealing members 3180 for sealing the interface between the first outer sealing mandrel 3040 and the first upper sealing head 3030. The sealing members 3180 may comprise any number of
5 conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3180 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first outer sealing mandrel 3040 may be coupled to the second upper
10 sealing head 3050 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the first outer sealing mandrel 3040 is removably coupled to the second upper sealing
15 head 3050 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first outer sealing mandrel 3040 and the second upper sealing head 3050 includes one or more sealing members 3185 for sealing the interface between the first outer sealing mandrel 3040 and the second upper sealing head 3050. The sealing members 3185 may comprise any number of
20 conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3185 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second inner sealing mandrel 3045 is coupled to the first lower sealing
25 head 3035 and the second lower sealing head 3055. The second inner sealing mandrel 3045 preferably comprises a substantially hollow tubular member or members. The second inner sealing mandrel 3045 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other
30 similar high strength materials. In a preferred embodiment, the second inner sealing mandrel 3045 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second inner sealing mandrel 3045 may be coupled to the first lower sealing head 3035 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded
5 connection or a standard threaded connection. In a preferred embodiment, the second inner sealing mandrel 3045 is removably coupled to the first lower sealing head 3035 by a standard threaded connection. The second inner sealing mandrel 3045 may be coupled to the second lower sealing head 3055 using any number of conventional commercially available mechanical couplings such as, for example,
10 drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection, or a standard threaded connection. In a preferred embodiment, the second inner sealing mandrel 3045 is removably coupled to the second lower sealing head 3055 by a standard threaded connection.

The second inner sealing mandrel 3045 preferably includes a fluid passage
15 3100 that is adapted to convey fluidic materials from the fluid passage 3095 into the fluid passage 3105. In a preferred embodiment, the fluid passage 3100 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The second inner sealing mandrel 3045 further preferably includes fluid
20 passages 3120 that are adapted to convey fluidic materials from the fluid passage 3100 into the second pressure chamber 3190 defined by the second upper sealing head 3050, the second lower sealing head 3055, the second inner sealing mandrel 3045, and the second outer sealing mandrel 3060. During operation of the
25 apparatus 3000, pressurization of the second pressure chamber 3190 causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070 to move in an axial direction.

The second upper sealing head 3050 is coupled to the first outer sealing
30 mandrel 3040 and the second outer sealing mandrel 3060. The second upper sealing head 3050 is also movably coupled to the outer surface of the second inner sealing mandrel 3045 and the inner surface of the casing 3075. In this manner, the

second upper sealing head 3050 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the second upper sealing head 3050 and the outer surface of the second inner sealing mandrel 3045 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the

5 radial clearance between the inner cylindrical surface of the second upper sealing head 3050 and the outer surface of the second inner sealing mandrel 3045 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the second upper sealing head 3050 and the inner surface of the casing 3075 may range, for

10 example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the second upper sealing head 3050 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process.

15 The second upper sealing head 3050 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second upper sealing head 3050 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength

20 materials. In a preferred embodiment, the second upper sealing head 3050 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the second upper sealing head 3050 preferably includes one or more annular sealing members 3195 for sealing the interface between the second upper sealing head 3050 and the

25 second inner sealing mandrel 3045. The sealing members 3195 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3195 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

30 In a preferred embodiment, the second upper sealing head 3050 includes a shoulder 3200 for supporting the first upper sealing head 3030, first outer sealing

mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 on the second lower sealing head 3055.

The second upper sealing head 3050 may be coupled to the first outer sealing mandrel 3040 using any number of conventional commercially available
5 mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second upper sealing head 3050 is removably coupled to the first outer sealing mandrel 3040 by a standard threaded connection. In a preferred embodiment, the
10 mechanical coupling between the second upper sealing head 3050 and the first outer sealing mandrel 3040 includes one or more sealing members 3185 for fluidically sealing the interface between the second upper sealing head 3050 and the first outer sealing mandrel 3040. The second upper sealing head 3050 may be coupled to the second outer sealing mandrel 3060 using any number of
15 conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second upper sealing head 3050 is removably coupled to the second outer sealing mandrel 3060 by a standard
20 threaded connection. In a preferred embodiment, the mechanical coupling between the second upper sealing head 3050 and the second outer sealing mandrel 3060 includes one or more sealing members 3205 for fluidically sealing the interface between the second upper sealing head 3050 and the second outer sealing mandrel 3060.

25 The second lower sealing head 3055 is coupled to the second inner sealing mandrel 3045 and the load mandrel 3065. The second lower sealing head 3055 is also movably coupled to the inner surface of the second outer sealing mandrel 3060. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing mandrel 3050, second outer sealing mandrel
30 3060, and expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the second lower sealing head 3055 and the inner surface of the second outer sealing mandrel 3060 may range, for example,

from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the second lower sealing head 3055 and the inner surface of the second outer sealing mandrel 3060 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

5 The second lower sealing head 3055 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second lower sealing head 3055 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength
10 materials. In a preferred embodiment, the second lower sealing head 3055 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the second lower sealing head 3055 preferably includes one or more annular sealing members 3210 for sealing the interface between the second lower sealing head 3055 and the
15 second outer sealing mandrel 3060. The sealing members 3210 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 3210 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

20 The second lower sealing head 3055 may be coupled to the second inner sealing mandrel 3045 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the second lower sealing head 3055 is
25 removably coupled to the second inner sealing mandrel 3045 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 3055 and the second inner sealing mandrel 3045 includes one or more sealing members 3215 for fluidically sealing the interface between the second lower sealing head 3055 and the second inner sealing mandrel
30 3045. The sealing members 3215 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing

members 3215 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 3055 may be coupled to the load mandrel 3065 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the second lower sealing head 3055 is removably coupled to the load mandrel 3065 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second lower sealing head 3055 and the load mandrel 3065 includes one or more sealing members 3220 for fluidically sealing the interface between the second lower sealing head 3055 and the load mandrel 3065. The sealing members 3220 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3220 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the second lower sealing head 3055 includes a throat passage 3225 fluidically coupled between the fluid passages 3100 and 3105. The throat passage 3225 is preferably of reduced size and is adapted to receive and engage with a plug 3230, or other similar device. In this manner, the fluid passage 3100 is fluidically isolated from the fluid passage 3105. In this manner, the pressure chambers 3175 and 3190 are pressurized. Furthermore, the placement of the plug 3230 in the throat passage 3225 also pressurizes the pressure chambers 3130 of the hydraulic slips 3025.

The second outer sealing mandrel 3060 is coupled to the second upper sealing head 3050 and the expansion cone 3070. The second outer sealing mandrel 3060 is also movably coupled to the inner surface of the casing 3075 and the outer surface of the second lower sealing head 3055. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the second outer sealing mandrel 3060 and the inner surface of the casing 3075 may

range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the second outer sealing mandrel 3060 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process. The radial clearance between the inner surface of the second outer sealing mandrel 3060 and the outer surface of the second lower sealing head 3055 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner surface of the second outer sealing mandrel 3060 and the outer surface of the second lower sealing head 3055 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second outer sealing mandrel 3060 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second outer sealing mandrel 3060 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second outer sealing mandrel 3060 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second outer sealing mandrel 3060 may be coupled to the second upper sealing head 3050 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 3060 is removably coupled to the second upper sealing head 3050 by a standard threaded connection. The second outer sealing mandrel 3060 may be coupled to the expansion cone 3070 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the second outer sealing mandrel 3060 is removably coupled to the expansion cone 3070 by a standard threaded connection.

The first upper sealing head 3030, the first lower sealing head 3035, the first inner sealing mandrel 3020, and the first outer sealing mandrel 3040 together define the first pressure chamber 3175. The second upper sealing head 3050, the second lower sealing head 3055, the second inner sealing mandrel 3045, and the second outer sealing mandrel 3060 together define the second pressure chamber 3190. The first and second pressure chambers, 3175 and 3190, are fluidically coupled to the passages, 3095 and 3100, via one or more passages, 3115 and 3120. During operation of the apparatus 3000, the plug 3230 engages with the throat passage 3225 to fluidically isolate the fluid passage 3100 from the fluid passage 3105.

10 The pressure chambers, 3175 and 3190, are then pressurized which in turn causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and expansion cone 3070 to reciprocate in the axial direction. The axial motion of the expansion cone 3070 in turn expands the casing 3075 in the radial direction. The use of a plurality of pressure chambers, 3175 and 3190, effectively multiplies the available driving force for the expansion cone 3070.

15

The load mandrel 3065 is coupled to the second lower sealing head 3055. The load mandrel 3065 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 3065 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 3065 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

20

25 The load mandrel 3065 may be coupled to the lower sealing head 3055 using any number of conventional commercially available mechanical couplings such as, for example, epoxy, cement, water, drilling mud, or lubricants. In a preferred embodiment, the load mandrel 3065 is removably coupled to the lower sealing head 3055 by a standard threaded connection.

30 The load mandrel 3065 preferably includes a fluid passage 3105 that is adapted to convey fluidic materials from the fluid passage 3100 to the region outside of the apparatus 3000. In a preferred embodiment, the fluid passage 3105

is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 3070 is coupled to the second outer sealing mandrel
5 3060. The expansion cone 3070 is also movably coupled to the inner surface of the casing 3075. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The reciprocation of the expansion cone 3070 causes the casing 3075 to expand in the radial
10 direction.

The expansion cone 3070 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges
15 from about 3 to 28 inches in order to optimally provide an expansion cone 3070 for expanding typical casings. The axial length of the expansion cone 3070 may range, for example, from about 2 to 8 times the maximum outer diameter of the expansion cone 3070. In a preferred embodiment, the axial length of the expansion cone 3070 ranges from about 3 to 5 times the maximum outer diameter of the
20 expansion cone 3070 in order to optimally provide stabilization and centralization of the expansion cone 3070 during the expansion process. In a particularly preferred embodiment, the maximum outside diameter of the expansion cone 3070 is between about 95 to 99 % of the inside diameter of the existing wellbore that the casing 3075 will be joined with. In a preferred embodiment, the angle of attack of
25 the expansion cone 3070 ranges from about 5 to 30 degrees in order to optimally balance the frictional forces with the radial expansion forces.

The expansion cone 3070 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics, or other similar high
30 strength materials. In a preferred embodiment, the expansion cone 3070 is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to wear and galling. In a particularly preferred embodiment, the

outside surface of the expansion cone 3070 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resistance to wear and galling.

The expansion cone 3070 may be coupled to the second outside sealing
5 mandrel 3060 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. In a preferred embodiment, the expansion cone 3070 is coupled to the second outside sealing mandrel 3060 using a standard
10 threaded connection in order to optimally provide high strength and easy disassembly.

The casing 3075 is removably coupled to the slips 3025 and the expansion cone 3070. The casing 3075 preferably comprises a tubular member. The casing 3075 may be fabricated from any number of conventional commercially available
15 materials such as, for example, slotted tubulars, oilfield country tubular goods, carbon steel, low alloy steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the casing 3075 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength.

20 In a preferred embodiment, the upper end 3235 of the casing 3075 includes a thin wall section 3240 and an outer annular sealing member 3245. In a preferred embodiment, the wall thickness of the thin wall section 3240 is about 50 to 100 % of the regular wall thickness of the casing 3075. In this manner, the upper end 3235 of the casing 3075 may be easily radially expanded and deformed into
25 intimate contact with the lower end of an existing section of wellbore casing. In a preferred embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section 3240 of casing 3075 into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside
30 diameter.

The annular sealing member 3245 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy,

rubber, metal or plastic. In a preferred embodiment, the annular sealing member 3245 is fabricated from StrataLock epoxy in order to optimally provide compressibility and wear resistance. The outside diameter of the annular sealing member 3245 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the wellbore casing that the casing 3075 is joined to. In this manner, after radial expansion, the annular sealing member 3245 optimally provides a fluidic seal and also preferably optimally provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing 3075 to support the casing 3075.

10 In a preferred embodiment, the lower end 3250 of the casing 3075 includes a thin wall section 3255 and an outer annular sealing member 3260. In a preferred embodiment, the wall thickness of the thin wall section 3255 is about 50 to 100 % of the regular wall thickness of the casing 3075. In this manner, the lower end 3250 of the casing 3075 may be easily expanded and deformed. Furthermore, in 15 this manner, an other section of casing may be easily joined with the lower end 3250 of the casing 3075 using a radial expansion process. In a preferred embodiment, the upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section of the upper end of the other casing into the thin walled section 3255 of the lower end 20 3250 of the casing 3075 results in a wellbore casing having a substantially constant inside diameter.

The upper annular sealing member 3245 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the upper 25 annular sealing member 3245 is fabricated from Stratalock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the upper annular sealing member 3245 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 3075 is joined to. In this manner, after radial expansion, the upper annular 30 sealing member 3245 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 3075 to support the casing 3075.

The lower annular sealing member 3260 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the lower annular sealing member 3260 is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the lower annular sealing member 3260 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 3075 is joined to. In this manner, the lower annular sealing member 3260 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 3075 to support the casing 3075.

During operation, the apparatus 3000 is preferably positioned in a wellbore with the upper end 3235 of the casing 3075 positioned in an overlapping relationship with the lower end of an existing wellbore casing. In a particularly preferred embodiment, the thin wall section 3240 of the casing 3075 is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing 3075 will compress the thin wall sections and annular compressible members of the upper end 3235 of the casing 3075 and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus 3000 in the wellbore, the casing 3000 is preferably supported by the expansion cone 3070.

After positioning the apparatus 3000, a first fluidic material is then pumped into the fluid passage 3080. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy, cement, slag mix or lubricants. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement, epoxy, or slag mix in order to optimally provide a hardenable outer annular body around the expanded casing 3075.

The first fluidic material may be pumped into the fluid passage 3080 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the first fluidic

material is pumped into the fluid passage 3080 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operating efficiency.

5 The first fluidic material pumped into the fluid passage 3080 passes through the fluid passages 3085, 3090, 3095, 3100, and 3105 and then outside of the apparatus 3000. The first fluidic material then preferably fills the annular region between the outside of the apparatus 3000 and the interior walls of the wellbore.

10 The plug 3230 is then introduced into the fluid passage 3080. The plug 3230 lodges in the throat passage 3225 and fluidically isolates and blocks off the fluid passage 3100. In a preferred embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage 3080 in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

15 A second fluidic material is then pumped into the fluid passage 3080. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud, drilling gases, or lubricant in order to optimally provide pressurization of the pressure
20 chambers 3175 and 3190.

The second fluidic material may be pumped into the fluid passage 3080 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the fluid passage 3080 at operating pressures and flow
25 rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The second fluidic material pumped into the fluid passage 3080 passes through the fluid passages 3085, 3090, 3095, 3100 and into the pressure chambers 3130 of the slips 3025, and into the pressure chambers 3175 and 3190. Continued
30 pumping of the second fluidic material pressurizes the pressure chambers 3130, 3175, and 3190.

The pressurization of the pressure chambers 3130 causes the hydraulic slip members 3140 to expand in the radial direction and grip the interior surface of the casing 3075. The casing 3075 is then preferably maintained in a substantially stationary position.

5 The pressurization of the pressure chambers 3175 and 3190 cause the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 to move in an axial direction relative to the casing 3075. In this manner, the expansion cone 3070 will cause the casing 3075 to expand in the radial direction, beginning
10 with the lower end 3250 of the casing 3075.

During the radial expansion process, the casing 3075 is prevented from moving in an upward direction by the slips 3025. A length of the casing 3075 is then expanded in the radial direction through the pressurization of the pressure chambers 3175 and 3190. The length of the casing 3075 that is expanded during
15 the expansion process will be proportional to the stroke length of the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, and expansion cone 3070.

Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the first upper sealing head 3030, first outer sealing
20 mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 drop to their rest positions with the casing 3075 supported by the expansion cone 3070. The reduction in the operating pressure of the second fluidic material also causes the spring bias 3135 of the slips 3025 to pull the slip members 3140 away from the inside walls of the casing 3075.

25 The position of the drillpipe 3075 is preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing 3235. In a preferred embodiment, the stroking of the expansion cone 3070 is then repeated, as necessary, until the thin walled section
30 3240 of the upper end 3235 of the casing 3075 is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially

constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

In a preferred embodiment, during the final stroke of the expansion cone
5 3070, the slips 3025 are positioned as close as possible to the thin walled section 3240 of the upper end 3235 of the casing 3075 in order minimize slippage between the casing 3075 and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the upper annular sealing member 3245 is selected to ensure sufficient interference fit with the inside
10 diameter of the lower end of the existing casing to prevent axial displacement of the casing 3075 during the final stroke. Alternatively, or in addition, the outside diameter of the lower annular sealing member 3260 is selected to provide an interference fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further axial displacement of the casing 3075.
15 In this final alternative, the interference fit is preferably selected to permit expansion of the casing 3075 by pulling the expansion cone 3070 out of the wellbore, without having to pressurize the pressure chambers 3175 and 3190.

During the radial expansion process, the pressurized areas of the apparatus 3000 are preferably limited to the fluid passages 3080, 3085, 3090, 3095, 3100,
20 3110, 3115, 3120, the pressure chambers 3130 within the slips 3025, and the pressure chambers 3175 and 3190. No fluid pressure acts directly on the casing 3075. This permits the use of operating pressures higher than the casing 3075 could normally withstand.

Once the casing 3075 has been completely expanded off of the expansion
25 cone 3070, the remaining portions of the apparatus 3000 are removed from the wellbore. In a preferred embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end 3235 of the casing 3075 ranges from about 400 to 10,000 psi in order to optimally support the casing 3075 using the existing
30 wellbore casing.

In this manner, the casing 3075 is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages 3080, 3085,

3090, 3095, 3100, 3110, 3115, and 3120, the pressure chambers 3130 of the slips 3025 and the pressure chambers 3175 and 3190 of the apparatus 3000.

In a preferred embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about
5 the expanded casing 3075. In the case where the casing 3075 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 3075. The resulting new section of wellbore casing includes the expanded casing 3075 and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing 3075 includes the deformed thin wall sections and
10 the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a
15 mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In a preferred embodiment, as the expansion cone 3070 nears the upper end 3235 of the casing 3075, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus 3000. In an alternative
20 embodiment, the apparatus 3000 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 3075.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 3070 nears the end of the casing 3075 in order to optimally provide reduced axial
25 movement and velocity of the expansion cone 3070. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 3000 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 3070 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 3000 ranges
30 from about 10 to 45 feet in order to optimally provide equipment that can be easily handled by typical oil well rigging equipment and also minimize the frequency at which the apparatus 3000 must be re-stroked.

In an alternative embodiment, at least a portion of one or both of the upper sealing heads, 3030 and 3050, includes an expansion cone for radially expanding the casing 3075 during operation of the apparatus 3000 in order to increase the surface area of the casing 3075 acted upon during the radial expansion process.

5 In this manner, the operating pressures can be reduced.

Alternatively, the apparatus 3000 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 3000 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 3000

10 may be used to expand a tubular support member in a hole.

Referring now to Figure 21, an apparatus 3330 for isolating subterranean zones will be described. A wellbore 3305 including a casing 3310 are positioned in a subterranean formation 3315. The subterranean formation 3315 includes a number of productive and non-productive zones, including a water zone 3320 and
15 a targeted oil sand zone 3325. During exploration of the subterranean formation 3315, the wellbore 3305 may be extended in a well known manner to traverse the various productive and non-productive zones, including the water zone 3320 and the targeted oil sand zone 3325.

In a preferred embodiment, in order to fluidically isolate the water zone 3320
20 from the targeted oil sand zone 3325, an apparatus 3330 is provided that includes one or more sections of solid casing 3335, one or more external seals 3340, one or more sections of slotted casing 3345, one or more intermediate sections of solid casing 3350, and a solid shoe 3355.

The solid casing 3335 may provide a fluid conduit that transmits fluids and
25 other materials from one end of the solid casing 3335 to the other end of the solid casing 3335. The solid casing 3335 may comprise any number of conventional commercially available sections of solid tubular casings such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. In a preferred embodiment, the solid casing 3335 comprises oilfield tubulars available from various foreign and
30 domestic steel mills.

The solid casing 3335 is preferably coupled to the casing 3310. The solid casing 3335 may be coupled to the casing 3310 using any number of conventional

commercially available processes such as, for example, welding, slotted and expandable connectors, or expandable solid connectors. In a preferred embodiment, the solid casing 3335 is coupled to the casing 3310 by using expandable solid connectors. The solid casing 3335 may comprise a plurality of
5 such solid casings 3335.

The solid casing 3335 is preferably coupled to one more of the slotted casings 3345. The solid casing 3335 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or slotted and expandable connectors. In a preferred
10 embodiment, the solid casing 3335 is coupled to the slotted casing 3345 by expandable solid connectors.

In a preferred embodiment, the casing 3335 includes one more valve members 3360 for controlling the flow of fluids and other materials within the interior region of the casing 3335. In an alternative embodiment, during the
15 production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

In a particularly preferred embodiment, the casing 3335 is placed into the wellbore 3305 by expanding the casing 3335 in the radial direction into intimate contact with the interior walls of the wellbore 3305. The casing 3335 may be expanded in the radial direction using any number of conventional commercially available methods. In a preferred embodiment, the casing 3335 is expanded in the
20 radial direction using one or more of the processes and apparatus described within the present disclosure.

The seals 3340 prevent the passage of fluids and other materials within the annular region 3365 between the solid casings 3335 and 3350 and the wellbore 3305. The seals 3340 may comprise any number of conventional commercially
25 available sealing materials suitable for sealing a casing in a wellbore such as, for example, lead, rubber or epoxy. In a preferred embodiment, the seals 3340 comprise Stratalok epoxy material available from Halliburton Energy Services.

The slotted casing 3345 permits fluids and other materials to pass into and out of the interior of the slotted casing 3345 from and to the annular region 3365. In this manner, oil and gas may be produced from a producing subterranean zone within a subterranean formation. The slotted casing 3345 may comprise any
5 number of conventional commercially available sections of slotted tubular casing. In a preferred embodiment, the slotted casing 3345 comprises expandable slotted tubular casing available from Petroline in Aberdeen, Scotland. In a particularly preferred embodiment, the slotted casing 145 comprises expandable slotted sandscreen tubular casing available from Petroline in Aberdeen, Scotland.

10 The slotted casing 3345 is preferably coupled to one or more solid casing 3335. The slotted casing 3345 may be coupled to the solid casing 3335 using any number of conventional commercially available processes such as, for example, welding, or slotted or solid expandable connectors. In a preferred embodiment, the slotted casing 3345 is coupled to the solid casing 3335 by expandable solid
15 connectors.

The slotted casing 3345 is preferably coupled to one or more intermediate solid casings 3350. The slotted casing 3345 may be coupled to the intermediate solid casing 3350 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors.
20 In a preferred embodiment, the slotted casing 3345 is coupled to the intermediate solid casing 3350 by expandable solid connectors.

The last section of slotted casing 3345 is preferably coupled to the shoe 3355. The last slotted casing 3345 may be coupled to the shoe 3355 using any number of conventional commercially available processes such as, for example,
25 welding or expandable solid or slotted connectors. In a preferred embodiment, the last slotted casing 3345 is coupled to the shoe 3355 by an expandable solid connector.

In an alternative embodiment, the shoe 3355 is coupled directly to the last one of the intermediate solid casings 3350.

30 In a preferred embodiment, the slotted casings 3345 are positioned within the wellbore 3305 by expanding the slotted casings 3345 in a radial direction into intimate contact with the interior walls of the wellbore 3305. The slotted casings

3345 may be expanded in a radial direction using any number of conventional commercially available processes. In a preferred embodiment, the slotted casings 3345 are expanded in the radial direction using one or more of the processes and apparatus disclosed in the present disclosure with reference to Figures 14a-20.

5 The intermediate solid casing 3350 permits fluids and other materials to pass between adjacent slotted casings 3345. The intermediate solid casing 3350 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. In a preferred embodiment, the intermediate solid casing 3350
10 comprises oilfield tubulars available from foreign and domestic steel mills.

 The intermediate solid casing 3350 is preferably coupled to one or more sections of the slotted casing 3345. The intermediate solid casing 3350 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or solid or slotted expandable
15 connectors. In a preferred embodiment, the intermediate solid casing 3350 is coupled to the slotted casing 3345 by expandable solid connectors. The intermediate solid casing 3350 may comprise a plurality of such intermediate solid casing 3350.

 In a preferred embodiment, each intermediate solid casing 3350 includes
20 one more valve members 3370 for controlling the flow of fluids and other materials within the interior region of the intermediate casing 3350. In an alternative embodiment, as will be recognized by persons having ordinary skill in the art and the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing,
25 sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

 In a particularly preferred embodiment, the intermediate casing 3350 is placed into the wellbore 3305 by expanding the intermediate casing 3350 in the
30 radial direction into intimate contact with the interior walls of the wellbore 3305. The intermediate casing 3350 may be expanded in the radial direction using any number of conventional commercially available methods.

In an alternative embodiment, one or more of the intermediate solid casings 3350 may be omitted. In an alternative preferred embodiment, one or more of the slotted casings 3345 are provided with one or more seals 3340.

The shoe 3355 provides a support member for the apparatus 3330. In this manner, various production and exploration tools may be supported by the shoe 3350. The shoe 3350 may comprise any number of conventional commercially available shoes suitable for use in a wellbore such as, for example, cement filled shoe, or an aluminum or composite shoe. In a preferred embodiment, the shoe 3350 comprises an aluminum shoe available from Halliburton. In a preferred embodiment, the shoe 3355 is selected to provide sufficient strength in compression and tension to permit the use of high capacity production and exploration tools.

In a particularly preferred embodiment, the apparatus 3330 includes a plurality of solid casings 3335, a plurality of seals 3340, a plurality of slotted casings 3345, a plurality of intermediate solid casings 3350, and a shoe 3355. More generally, the apparatus 3330 may comprise one or more solid casings 3335, each with one or more valve members 3360, n slotted casings 3345, n-1 intermediate solid casings 3350, each with one or more valve members 3370, and a shoe 3355.

During operation of the apparatus 3330, oil and gas may be controllably produced from the targeted oil sand zone 3325 using the slotted casings 3345. The oil and gas may then be transported to a surface location using the solid casing 3335. The use of intermediate solid casings 3350 with valve members 3370 permits isolated sections of the zone 3325 to be selectively isolated for production. The seals 3340 permit the zone 3325 to be fluidically isolated from the zone 3320. The seals 3340 further permits isolated sections of the zone 3325 to be fluidically isolated from each other. In this manner, the apparatus 3330 permits unwanted and/or non-productive subterranean zones to be fluidically isolated.

In an alternative embodiment, as will be recognized by persons having ordinary skill in the art and also having the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and

isolating subterranean zones from each other while providing a fluid path to the surface.

Referring to Figures 22a, 22b, 22c and 22d, an embodiment of an apparatus 3500 for forming a wellbore casing while drilling a wellbore will now be described.

5 In a preferred embodiment, the apparatus 3500 includes a support member 3505, a mandrel 3510, a mandrel launcher 3515, a shoe 3520, a tubular member 3525, a mud motor 3530, a drill bit 3535, a first fluid passage 3540, a second fluid passage 3545, a pressure chamber 3550, a third fluid passage 3555, a cup seal 3560, a body of lubricant 3565, seals 3570, and a releasable coupling 3600.

10 The support member 3505 is coupled to the mandrel 3510. The support member 3505 preferably comprises an annular member having sufficient strength to carry and support the apparatus 3500 within the wellbore 3575. In a preferred embodiment, the support member 3505 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 3500.

15 The support member 3505 may comprise one or more sections of conventional commercially available tubular materials such as, for example, oilfield country tubular goods, low alloy steel, stainless steel or carbon steel. In a preferred embodiment, the support member 3505 comprises coiled tubing or drillpipe in order to optimally permit the placement of the apparatus 3500 within
20 a non-vertical wellbore.

In a preferred embodiment, the support member 3505 includes a first fluid passage 3540 for conveying fluidic materials from a surface location to the fluid passage 3545. In a preferred embodiment, the first fluid passage 3540 is adapted to convey fluidic materials such as water, drilling mud, cement, epoxy or slag mix
25 at operating pressures and flow rates ranging from about 0 to 10,000 psi and 0 to 3,000 gallons/minute.

The mandrel 3510 is coupled to and supported by the support member 3505. The mandrel 3510 is also coupled to and supports the mandrel launcher 3515 and tubular member 3525. The mandrel 3510 is preferably adapted to controllably
30 expand in a radial direction. The mandrel 3510 may comprise any number of conventional commercially available mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the mandrel 3510

comprises a hydraulic expansion tool as disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

In a preferred embodiment, the mandrel 3510 includes one or more conical sections for expanding the tubular member 3525 in the radial direction. In a preferred embodiment, the outer surfaces of the conical sections of the mandrel 3510 have a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally radially expand the tubular member 3525.

In a preferred embodiment, the mandrel 3510 includes a second fluid passage 3545 fluidically coupled to the first fluid passage 3540 and the pressure chamber 3550 for conveying fluidic materials from the first fluid passage 3540 to the pressure chamber 3550. In a preferred embodiment, the second fluid passage 3545 is adapted to convey fluidic materials such as water, drilling mud, cement, epoxy or slag mix at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 3,500 gallons/minute in order to optimally provide operating pressure for efficient operation.

The mandrel launcher 3515 is coupled to the tubular member 3525, the mandrel 3510, and the shoe 3520. The mandrel launcher 3515 preferably comprises a tapered annular member that mates with at a portion of at least one of the conical portions of the outer surface of the mandrel 3510. In a preferred embodiment, the wall thickness of the mandrel launcher is less than the wall thickness of the tubular member 3525 in order to facilitate the initiation of the radial expansion process and facilitate the placement of the apparatus in openings having tight clearances. In a preferred embodiment, the wall thickness of the mandrel launcher 3515 ranges from about 50 to 100 % of the wall thickness of the tubular member 3525 immediately adjacent to the mandrel launcher 3515 in order to optimally facilitate the radial expansion process and facilitate the insertion of the apparatus 3500 into wellbore casings and other areas with tight clearances.

The mandrel launcher 3515 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel or stainless steel. In a preferred embodiment, the mandrel launcher 3515 is fabricated from oilfield

country tubular goods of higher strength by lower wall thickness than the tubular member 3525 in order to optimally provide a smaller container having approximately the same burst strength as the tubular member 3525.

The shoe 3520 is coupled to the mandrel launcher 3515 and the releasable
5 coupling 3600. The shoe 3520 preferably comprises a substantially annular member. In a preferred embodiment, the shoe 3520 or the releasable coupling 3600 include a third fluid passage 3555 fluidically coupled to the pressure chamber 3550 and the mud motor 3530.

The shoe 3520 may comprise any number of conventional commercially
10 available shoes such as, for example, cement filled, aluminum or composite modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 3520 comprises a high strength shoe having a burst strength approximately equal to the burst strength of the tubular member 3525 and mandrel launcher 3515. The shoe 3520 is preferably coupled to the mud motor
15 3520 by a releasable coupling 3600 in order to optimally provide for removal of the mud motor 3530 and drill bit 3535 upon the completion of a drilling and casing operation.

In a preferred embodiment, the shoe 3520 includes a releasable latch
mechanism 3600 for retrieving and removing the mud motor 3530 and drill bit
20 3535 upon the completion of the drilling and casing formation operations. In a preferred embodiment, the shoe 3520 further includes an anti-rotation device for maintaining the shoe 3520 in a substantially stationary rotational position during operation of the apparatus 3500. In a preferred embodiment, the releasable latch mechanism 3600 is releasably coupled to the shoe 3520.

25 The tubular member 3525 is supported by and coupled to the mandrel 3510. The tubular member 3525 is expanded in the radial direction and extruded off of the mandrel 3510. The tubular member 3525 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, automotive
30 grade steel, or plastic tubing/casing. In a preferred embodiment, the tubular member 3525 is fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 3525 may range,

for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the inner and outer diameters of the tubular member 3525 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most
5 commonly drilled wellbore sizes. The tubular member 3525 preferably comprises an annular member with solid walls.

In a preferred embodiment, the upper end portion 3580 of the tubular member 3525 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 3510 when the mandrel 3510 completes the extrusion of tubular
10 member 3525. For typical tubular member 3525 materials, the length of the tubular member 3525 is preferably limited to between about 40 to 20,000 feet in length. The tubular member 3525 may comprise a single tubular member or, alternatively, a plurality of tubular members coupled to one another.

The mud motor 3530 is coupled to the shoe 3520 and the drill bit 3535. The
15 mud motor 3530 is also fluidically coupled to the fluid passage 3555. In a preferred embodiment, the mud motor 3530 is driven by fluidic materials such as, for example, drilling mud, water, cement, epoxy, lubricants or slag mix conveyed from the fluid passage 3555 to the mud motor 3530. In this manner, the mud motor 3530 drives the drill bit 3535. The operating pressures and flow rates for operating
20 mud motor 3530 may range, for example, from about 0 to 12,000 psi and 0 to 10,000 gallons/minute. In a preferred embodiment, the operating pressures and flow rates for operating mud motor 3530 range from about 0 to 5,000 psi and 40 to 3,000 gallons/minute.

The mud motor 3530 may comprise any number of conventional
25 commercially available mud motors, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the size of the mud motor 3520 and drill bit 3535 are selected to pass through the interior of the shoe 3520 and the expanded tubular member 3525. In this manner, the mud motor 3520 and drill bit 3535 may be retrieved from the downhole location upon the conclusion of the
30 drilling and casing operations.

The drill bit 3535 is coupled to the mud motor 3530. The drill bit 3535 is preferably adapted to be powered by the mud motor 3530. In this manner, the drill bit 3535 drills out new sections of the wellbore 3575.

The drill bit 3535 may comprise any number of conventional commercially
5 available drill bits, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the size of the mud motor 3520 and drill bit 3535 are selected to pass through the interior of the shoe 3520 and the expanded tubular member 3525. In this manner, the mud motor 3520 and drill bit 3535 may be retrieved from the downhole location upon the conclusion of the
10 drilling and casing operations. In several alternative preferred embodiments, the drill bit 3535 comprises an eccentric drill bit, a bi-centered drill bit, or a small diameter drill bit with an hydraulically actuated under reamer.

The first fluid passage 3540 permits fluidic materials to be transported to the second fluid passage 3545, the pressure chamber 3550, the third fluid passage
15 3555, and the mud motor 3530. The first fluid passage 3540 is coupled to and positioned within the support member 3505. The first fluid passage 3540 preferably extends from a position adjacent to the surface to the second fluid passage 3545 within the mandrel 3510. The first fluid passage 3540 is preferably positioned along a centerline of the apparatus 3500.

20 The second fluid passage 3545 permits fluidic materials to be conveyed from the first fluid passage 3540 to the pressure chamber 3550, the third fluid passage 3555, and the mud motor 3530. The second fluid passage 3545 is coupled to and positioned within the mandrel 3510. The second fluid passage 3545 preferably extends from a position adjacent to the first fluid passage 3540 to the bottom of the
25 mandrel 3510. The second fluid passage 3545 is preferably positioned substantially along the centerline of the apparatus 3500.

The pressure chamber 3550 permits fluidic materials to be conveyed from the second fluid passage 3545 to the third fluid passage 3555, and the mud motor 3530. The pressure chamber is preferably defined by the region below the mandrel
30 3510 and within the tubular member 3525, mandrel launcher 3515, shoe 3520, and releasable coupling 3600. During operation of the apparatus 3500, pressurization

of the pressure chamber 3550 preferably causes the tubular member 3525 to be extruded off of the mandrel 3510.

The third fluid passage 3555 permits fluidic materials to be conveyed from the pressure chamber 3550 to the mud motor 3530. The third fluid passage 3555
5 may be coupled to and positioned within the shoe 3520 or releasable coupling 3600. The third fluid passage 3555 preferably extends from a position adjacent to the pressure chamber 3550 to the bottom of the shoe 3520 or releasable coupling 3600. The third fluid passage 3555 is preferably positioned substantially along the centerline of the apparatus 3500.

10 The fluid passages 3540, 3545, and 3555 are preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally operational efficiency.

The cup seal 3560 is coupled to and supported by the outer surface of the
15 support member 3505. The cup seal 3560 prevents foreign materials from entering the interior region of the tubular member 3525. The cup seal 3560 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the cup seal 3560 comprises a SIP cup,
20 available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant. In a preferred embodiment, the apparatus 3500 includes a plurality of such cup seals in order to optimally prevent the entry of foreign material into the interior region of the tubular member 3525 in the vicinity of the mandrel 3510.

25 In a preferred embodiment, a quantity of lubricant 3565 is provided in the annular region above the mandrel 3510 within the interior of the tubular member 3525. In this manner, the extrusion of the tubular member 3525 off of the mandrel 3510 is facilitated. The lubricant 3565 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate,
30 chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 3565 comprises Climax 1500 Antisieze

(3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

The seals 3570 are coupled to and supported by the end portion 3580 of the tubular member 3525. The seals 3570 are further positioned on an outer surface
5 of the end portion 3580 of the tubular member 3525. The seals 3570 permit the overlapping joint between the lower end portion 3585 of a preexisting section of casing 3590 and the end portion 3580 of the tubular member 3525 to be fluidically sealed. The seals 3570 may comprise any number of conventional commercially
10 available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 3570 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 3580 of the tubular member 3525 and the
end 3585 of the pre-existing casing 3590.

15 In a preferred embodiment, the seals 3570 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 3525 from the pre-existing casing 3590. In a preferred embodiment, the frictional force optimally provided by the seals 3570 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 3525.

20 The releasable coupling 3600 is preferably releasably coupled to the bottom of the shoe 3520. In a preferred embodiment, the releasable coupling 3600 includes fluidic seals for sealing the interface between the releasable coupling 3600 and the shoe 3520. In this manner, the pressure chamber 3550 may be pressurized. The releasable coupling 3600 may comprise any number of
25 conventional commercially available releasable couplings suitable for drilling operations modified in accordance with the teachings of the present disclosure.

As illustrated in Figure 22A, during operation of the apparatus 3500, the apparatus 3500 is preferably initially positioned within a preexisting section of a wellbore 3575 including a preexisting section of wellbore casing 3590. In a
30 preferred embodiment, the upper end portion 3580 of the tubular member 3525 is positioned in an overlapping relationship with the lower end 3585 of the preexisting section of casing 3590. In a preferred embodiment, the apparatus 3500

is initially positioned in the wellbore 3575 with the drill bit 353 in contact with the bottom of the wellbore 3575. During the initial placement of the apparatus 3500 in the wellbore 3575, the tubular member 3525 is preferably supported by the mandrel 3510.

5 As illustrated in Figure 22B, a fluidic material 3595 is then pumped into the first fluid passage 3540. The fluidic material 3595 is preferably conveyed from the first fluid passage 3540 to the second fluid passage 3545, the pressure chamber 3550, the third fluid passage 3555 and the inlet to the mud motor 3530. The fluidic material 3595 may comprise any number of conventional commercially
10 available fluidic materials such as, for example, drilling mud, water, cement, epoxy or slag mix. The fluidic material 3595 may be pumped into the first fluid passage 3540 at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The fluidic material 3595 will enter the inlet for the mud motor 3530 and
15 drive the mud motor 3530. The fluidic material 3595 will then exit the mud motor 3530 and enter the annular region surrounding the apparatus 3500 within the wellbore 3575. The mud motor 3530 will in turn drive the drill bit 3535. The operation of the drill bit 3535 will drill out a new section of the wellbore 3575.

In the case where the fluidic material 3595 comprises a hardenable fluidic
20 material, the fluidic material 3595 preferably is permitted to cure and form an outer annular body surrounding the periphery of the expanded tubular member 3525. Alternatively, in the case where the fluidic material 3595 is a non-hardenable fluidic material, the tubular member 3595 preferably is expanded into intimate contact with the interior walls of the wellbore 3575. In this manner, an
25 outer annular body is not provided in all applications.

As illustrated in Figure 22C, at some point during operation of the mud motor 3530 and drill bit 3535, the pressure drop across the mud motor 3530 will create sufficient back pressure to cause the operating pressure within the pressure chamber 3550 to elevate to the pressure necessary to extrude the tubular member
30 3525 off of the mandrel 3510. The elevation of the operating pressure within the pressure chamber 3550 will then cause the tubular member 3525 to extrude off of the mandrel 3510 as illustrated in Figure 22D. For typical tubular members 3525,

the necessary operating pressure may range, for example, from about 1,000 to 9,000 psi. In this manner, a wellbore casing is formed simultaneous with the drilling out of a new section of wellbore.

In a particularly preferred embodiment, during the operation of the apparatus 3500, the apparatus 3500 is lowered into the wellbore 3575 until the drill bit 3535 is proximate the bottom of the wellbore 3575. Throughout this process, the tubular member 3525 is preferably supported by the mandrel 3510. The apparatus 3500 is then lowered until the drill bit 3535 is placed in contact with the bottom of the wellbore 3575. At this point, at least a portion of the weight of the tubular member 3525 is supported by the drill bit 3535.

The fluidic material 3595 is then pumped into the first fluid passage 3540, second fluid passage 3545, pressure chamber 3550, third fluid passage 3555, and the inlet of the mud motor 3530. The mud motor 3530 then drives the drill bit 3535 to drill out a new section of the wellbore 3575. Once the differential pressure across the mud motor 3530 exceeds the minimum extrusion pressure for the tubular member 3525, the tubular member 3525 begins to extrude off of the mandrel 3510. As the tubular member 3525 is extruded off of the mandrel 3510, the weight of the extruded portion of the tubular member 3525 is transferred to and supported by the drill bit 3535. In a preferred embodiment, the pumping pressure of the fluidic material 3595 is maintained substantially constant throughout this process. At some point during the process of extruding the tubular member 3525 off of the mandrel 3510, a sufficient portion of the weight of the tubular member 3525 is transferred to the drill bit 3535 to stop the extrusion process due to the opposing force. Continued drilling by the drill bit 3535 eventually transfers a sufficient portion of the weight of the extruded portion of the tubular member 3525 back to the mandrel 3510. At this point, the extrusion of the tubular member 3525 off of the mandrel 3510 continues. In this manner, the support member 3505 never has to be moved and no drillpipe connections have to be made at the surface since the new section of the wellbore casing within the newly drilled section of wellbore is created by the constant downward feeding of the expanded tubular member 3525 off of the mandrel 3510.

Once the new section of wellbore that is lined with the fully expanded tubular member 3525 is completed, the support member 3505 and mandrel 3510 are removed from the wellbore 3575. The drilling assembly including the mud motor 3530 and drill bit 3535 are then preferably removed by lowering a drillstring
5 into the new section of wellbore casing and retrieving the drilling assembly by using the latch 3600. The expanded tubular member 3525 is then cemented using conventional squeeze cementing methods to provide a solid annular sealing member around the periphery of the expanded tubular member 3525.

Alternatively, the apparatus 3500 may be used to repair or form an
10 underground pipeline or form a support member for a structure. In several preferred alternative embodiments, the teachings of the apparatus 3500 are combined with the teachings of the embodiments illustrated in Figures 1-21. For example, by operably coupling the mud motor 3530 and drill bit 3535 to the pressure chambers used to cause the radial expansion of the tubular members of
15 the embodiments illustrated and described with reference to Figures 1-21, the use of plugs may be eliminated and radial expansion of tubular members can be combined with the drilling out of new sections of wellbore.

Referring now to FIGS. 23A, 23B and 23C, an apparatus 3700 for expanding a tubular member will be described. In a preferred embodiment, the apparatus
20 3700 includes a support member 3705, a packer 3710, a first fluid conduit 3715, an annular fluid passage 3720, fluid inlets 3725, an annular seal 3730, a second fluid conduit 3735, a fluid passage 3740, a mandrel 3745, a mandrel launcher 3750, a tubular member 3755, slips 3760, and seals 3765. In a preferred embodiment, the apparatus 3700 is used to radially expand the tubular member 3755. In this
25 manner, the apparatus 3700 may be used to form a wellbore casing, line a wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a wellbore casing, pipeline or structural support member. In a preferred embodiment, the apparatus 3700 is used to clad at least a portion of the tubular member 3755 onto a preexisting tubular member.

30 The support member 3705 is preferably coupled to the packer 3710 and the mandrel launcher 3750. The support member 3705 preferably comprises a tubular member fabricated from any number of conventional commercially available

materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 3705 is preferably selected to fit through a preexisting section of wellbore casing 3770. In this manner, the apparatus 3700 may be positioned within the wellbore casing 3770. In a preferred
5 embodiment, the support member 3705 is releasably coupled to the mandrel launcher 3750. In this manner, the support member 3705 may be decoupled from the mandrel launcher 3750 upon the completion of an extrusion operation.

The packer 3710 is coupled to the support member 3705 and the first fluid conduit 3715. The packer 3710 preferably provides a fluid seal between the
10 outside surface of the first fluid conduit 3715 and the inside surface of the support member 3705. In this manner, the packer 3710 preferably seals off and, in combination with the support member 3705, first fluid conduit 3715, second fluid conduit 3735, and mandrel 3745, defines an annular chamber 3775. The packer 3710 may comprise any number of conventional commercially available packers
15 modified in accordance with the teachings of the present disclosure.

The first fluid conduit 3715 is coupled to the packer 3710 and the annular seal 3730. The first fluid conduit 3715 preferably comprises an annular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or
20 stainless steel. In a preferred embodiment, the first fluid conduit 3715 includes one or more fluid inlets 3725 for conveying fluidic materials from the annular fluid passage 3720 into the chamber 3775.

The annular fluid passage 3720 is defined by and positioned between the interior surface of the first fluid conduit 3715 and the interior surface of the
25 second fluid conduit 3735. The annular fluid passage 3720 is preferably adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The fluid inlets 3725 are positioned in an end portion of the first fluid
30 conduit 3715. The fluid inlets 3725 preferably are adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating

pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The annular seal 3730 is coupled to the first fluid conduit 3715 and the second fluid conduit 3735. The annular seal 3730 preferably provides a fluid seal
5 between the interior surface of the first fluid conduit 3715 and the exterior surface of the second fluid conduit 3735. The annular seal 3730 preferably provides a fluid seal between the interior surface of the first fluid conduit 3715 and the exterior surface of the second fluid conduit 3735 during relative axial motion of the first fluid conduit 3715 and the second fluid conduit 3735. The annular seal 3730 may
10 comprise any number of conventional commercially available seals such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the annular seal 3730 comprises a polypak seal available from Parker Seals in order to optimally provide sealing for axial motion.

The second fluid conduit 3735 is coupled to the annular seal 3730 and the
15 mandrel 3745. The second fluid conduit preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, coiled tubing, oilfield country tubular goods, low alloy steel, stainless steel, or low carbon steel. In a preferred embodiment, the second fluid conduit 3735 is adapted to convey fluidic materials such as cement, water, epoxy,
20 lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The fluid passage 3740 is coupled to the second fluid conduit 3735 and the mandrel 3745. In a preferred embodiment, the fluid passage 3740 is adapted to
25 convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The mandrel 3745 is coupled to the second fluid conduit 3735 and the mandrel launcher 3750. The mandrel 3745 preferably comprise an annular
30 member having a conic section fabricated from any number of conventional commercially available materials such as, for example, carbon steel, tool steel, ceramics, or composite materials. In a preferred embodiment, the angle of attack

the conic section of the mandrel 3745 ranges from about 10 to 30 degrees in order to optimally expand the mandrel launcher 3750 and tubular member 3755 in the radial direction. In a preferred embodiment, the surface hardness of the conic section of the mandrel 3745 ranges from about 50 Rockwell C to 70 Rockwell C.

5 In a particularly preferred embodiment, the surface hardness of the outer surface of the conic section of the mandrel 3745 ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In an alternative embodiment, the mandrel 3745 is expandable in order to further optimally augment the radial expansion process.

10 The mandrel launcher 3750 is coupled to the support member 3705, the mandrel 3745, and the tubular member 3755. The mandrel launcher 3750 preferably comprise a tubular member having a variable cross-section and a reduced wall thickness in order to facilitate the radial expansion process. In a preferred embodiment, the cross-sectional area of the mandrel launcher 3750 at
15 one end is adapted to mate with the mandrel 3745, and at the other end, the cross-sectional area of the mandrel launcher 3750 is adapted to match the cross-sectional area of the tubular member 3755. In a preferred embodiment, the wall thickness of the mandrel launcher 3750 ranges from about 50 to 100 % of the wall thickness of the tubular member 3755 in order to facilitate the initiation of the radial
20 expansion process.

The mandrel launcher 3750 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, stainless steel, or carbon steel. In a preferred embodiment, the mandrel launcher 3750 is fabricated from oilfield
25 country tubular goods having higher strength but lower wall thickness than the tubular member 3755 in order to optimally match the burst strength of the tubular member 3755. In a preferred embodiment, the mandrel launcher 3750 is removably coupled to the tubular member 3755. In this manner, the mandrel launcher 3750 may be removed from the wellbore 3780 upon the completion of an
30 extrusion operation.

The tubular member 3755 is coupled to the mandrel launcher, the slips 3760 and the seals 3765. The tubular member 3755 preferably comprises a tubular

member fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel, or oilfield country tubular goods. In a preferred embodiment, the tubular member 3755 is fabricated from oilfield country tubular goods.

5 The slips 3760 are coupled to the outside surface of the tubular member 3755. The slips 3760 preferably are adapted to couple to the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3755. In this manner, the slips 3760 provide structural support for the expanded tubular member 3755. The slips 3760 may comprise any number of
10 conventional commercially available slips, modified in accordance with the teachings of the present disclosure.

 The seals 3765 are coupled to the outside surface of the tubular member 3755. The seals 3765 preferably provide a fluidic seal between the outside surface of the expanded tubular member 3755 and the interior walls of a casing, pipeline
15 or other structure upon the radial expansion of the tubular member 3755. In this manner, the seals 3765 provide a fluidic seal for the expanded tubular member 3755. The seals 3765 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred
20 embodiment, the seals 3765 comprise seals molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a hydraulic seal in the overlapping joint and optimally provide load carrying capacity to withstand the range of typical tensile and compressive loads.

 During operation of the apparatus 3700, the apparatus 3700 is preferably
25 lowered into a wellbore 3780 having a preexisting section of wellbore casing 3770. In a preferred embodiment, the apparatus 3700 is positioned with at least a portion of the tubular member 3755 overlapping with a portion of the wellbore casing 3770. In this manner, the radial expansion of the tubular member 3755 will preferably cause the outside surface of the expanded tubular member 3755 to
30 couple with the inside surface of the wellbore casing 3770. In a preferred embodiment, the radial expansion of the tubular member 3755 will also cause the slips 3760 and seals 3765 to engage with the interior surface of the wellbore casing

3770. In this manner, the expanded tubular member 3755 is provided with enhanced structural support by the slips 3760 and an enhanced fluid seal by the seals 3765.

As illustrated in FIG. 23B, after placement of the apparatus 3700 in an overlapping relationship with the wellbore casing 3770, a fluidic material 3785 is preferably pumped into the chamber 3775 using the fluid passage 3720 and the inlet passages 3725. In a preferred embodiment, the fluidic material is pumped into the chamber 3775 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency. The pumped fluidic material 3785 increase the operating pressure within the chamber 3775. The increased operating pressure in the chamber 3775 then causes the mandrel 3745 to extrude the mandrel launcher 3750 and tubular member 3755 off of the face of the mandrel 3745. The extrusion of the mandrel launcher 3750 and tubular member 3755 off of the face of the mandrel 3745 causes the mandrel launcher 3750 and tubular member 3755 to expand in the radial direction. Continued pumping of the fluidic material 3785 preferably causes the entire length of the tubular member 3755 to expand in the radial direction.

In a preferred embodiment, the pumping rate and pressure of the fluidic material 3785 is reduced during the latter stages of the extrusion process in order to minimize shock to the apparatus 3700. In a preferred embodiment, the apparatus 3700 includes shock absorbers for absorbing the shock caused by the completion of the extrusion process.

In a preferred embodiment, the extrusion process causes the mandrel 3745 to move in an axial direction 3785. During the axial movement of the mandrel, in a preferred embodiment, the fluid passage 3740 conveys fluidic material 3790 displaced by the moving mandrel 3745 out of the wellbore 3780. In this manner, the operational efficiency and speed of the extrusion process is enhanced.

In a preferred embodiment, the extrusion process includes the injection of a hardenable fluidic material into the annular region between the tubular member 3755 and the bore hole 3780. In this manner, a hardened sealing layer is provided between the expanded tubular member 3755 and the interior walls of the wellbore 3780.

As illustrated in FIG. 23C, in a preferred embodiment, upon the completion of the extrusion process, the support member 3705, packer 3710, first fluid conduit 3715, annular seal 3730, second fluid conduit 3735, mandrel 3745, and mandrel launcher 3750 are moved from the wellbore 3780.

5 In an alternative embodiment, the apparatus 3700 is used to repair a preexisting wellbore casing, pipeline, or structural support. In this alternative embodiment, both ends of the tubular member 3755 preferably include slips 3760 and seals 3765.

10 In an alternative embodiment, the apparatus 3700 is used to form a tubular structural support for a building or offshore structure.

Referring now to FIGS. 24A, 24B, 24C, 24D, and 24E, an apparatus 3900 for expanding a tubular member will be described. In a preferred embodiment, the apparatus 3900 includes a support member 3905, a mandrel launcher 3910, a mandrel 3915, a first fluid passage 3920, a tubular member 3925, slips 3930, seals 15 3935, a shoe 3940, and a second fluid passage 3945. In a preferred embodiment, the apparatus 3900 is used to radially expand the mandrel launcher 3910 and tubular member 3925. In this manner, the apparatus 3900 may be used to form a wellbore casing, line a wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a wellbore casing, pipeline or structural 20 support member. In a preferred embodiment, the apparatus 3900 is used to clad at least a portion of the tubular member 3925 onto a preexisting structural member.

The support member 3905 is preferably coupled to the mandrel launcher 3910. The support member 3905 preferably comprises a tubular member 25 fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 3905, the mandrel launcher 3910, the tubular member 3925, and the shoe 3940 are preferably selected to fit through a preexisting section of wellbore casing 3950. In this manner, the apparatus 3900 30 may be positioned within the wellbore casing 3970. In a preferred embodiment, the support member 3905 is releasably coupled to the mandrel launcher 3910. In

this manner, the support member 3905 may be decoupled from the mandrel launcher 3910 upon the completion of an extrusion operation.

The mandrel launcher 3910 is coupled to the support member 3905 and the tubular member 3925. The mandrel launcher 3910 preferably comprise a tubular member having a variable cross-section and a reduced wall thickness in order to facilitate the radial expansion process. In a preferred embodiment, the cross-sectional area of the mandrel launcher 3910 at one end is adapted to mate with the mandrel 3915, and at the other end, the cross-sectional area of the mandrel launcher 3910 is adapted to match the cross-sectional area of the tubular member 3925. In a preferred embodiment, the wall thickness of the mandrel launcher 3910 ranges from about 50 to 100 % of the wall thickness of the tubular member 3925 in order to facilitate the initiation of the radial expansion process.

The mandrel launcher 3910 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, stainless steel, or carbon steel. In a preferred embodiment, the mandrel launcher 3910 is fabricated from oilfield country tubular goods having higher strength but lower wall thickness than the tubular member 3925 in order to optimally match the burst strength of the tubular member 3925. In a preferred embodiment, the mandrel launcher 3910 is removably coupled to the tubular member 3925. In this manner, the mandrel launcher 3910 may be removed from the wellbore 3960 upon the completion of an extrusion operation.

The mandrel 3915 is coupled to the mandrel launcher 3910. The mandrel 3915 preferably comprise an annular member having a conic section fabricated from any number of conventional commercially available materials such as, for example, tool steel, carbon steel, ceramics, or composite materials. In a preferred embodiment, the angle of attack of the conic section of the mandrel 3915 ranges from about 10 to 30 degrees in order to optimally expand the mandrel launcher 3910 and the tubular member 3925 in the radial direction. In a preferred embodiment, the surface hardness of the conic section of the mandrel 3915 ranges from about 58 to 62 Rockwell C in order to optimally provide high strength and

resist wear and galling. In an alternative embodiment, the mandrel 3915 is expandable in order to further optimally augment the radial expansion process.

The fluid passage 3920 is positioned within the mandrel 3915. The fluid passage 3920 is preferably adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency. The fluid passage 3920 preferably includes an inlet 3965 adapted to receive a plug, or other similar device. In this manner, the interior chamber 3970 above the mandrel 3915 may be fluidically isolated from the interior chamber 3975 below the mandrel 3915.

The tubular member 3925 is coupled to the mandrel launcher 3910, the slips 3930 and the seals 3935. The tubular member 3925 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel, or oilfield country tubular goods. In a preferred embodiment, the tubular member 3925 is fabricated from oilfield country tubular goods.

The slips 3930 are coupled to the outside surface of the tubular member 3925. The slips 3930 preferably are adapted to couple to the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3925. In this manner, the slips 3930 provide structural support for the expanded tubular member 3925. The slips 3930 may comprise any number of conventional commercially available slips, modified in accordance with the teachings of the present disclosure.

The seals 3935 are coupled to the outside surface of the tubular member 3925. The seals 3935 preferably provide a fluidic seal between the outside surface of the expanded tubular member 3925 and the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3925. In this manner, the seals 3935 provide a fluidic seal for the expanded tubular member 3925. The seals 3935 may comprise any number of conventional commercially available seals such as, for example, lead, rubber or epoxy. In a preferred embodiment, the seals 3935 comprise Stratalok epoxy material available from

Halliburton Energy Services in order to optimally provide structural support for the typical tensile and compressive loads.

The shoe 3940 is coupled to the tubular member 3925. The shoe 3940 preferably comprises a substantially tubular member having a fluid passage 3945
5 for conveying fluidic materials from the chamber 3975 to the annular region 3970 outside of the apparatus 3900. The shoe 3940 may comprise any number of conventional commercially available shoes modified in accordance with the teachings of the present disclosure.

During operation of the apparatus 3900, the apparatus 3900 is preferably
10 lowered into a wellbore 3960 having a preexisting section of wellbore casing 3975. In a preferred embodiment, the apparatus 3900 is positioned with at least a portion of the tubular member 3925 overlapping with a portion of the wellbore casing 3975. In this manner, the radial expansion of the tubular member 3925 will preferably cause the outside surface of the expanded tubular member 3925 to
15 couple with the inside surface of the wellbore casing 3975. In a preferred embodiment, the radial expansion of the tubular member 3925 will also cause the slips 3930 and seals 3935 to engage with the interior surface of the wellbore casing 3975. In this manner, the expanded tubular member 3925 is provided with enhanced structural support by the slips 3930 and an enhanced fluid seal by the
20 seals 3935.

As illustrated in FIG. 24B, after placement of the apparatus 3900 in an overlapping relationship with the wellbore casing 3975, a fluidic material 3980 is preferably pumped into the chamber 3970. The fluidic material 3980 then passes through the fluid passage 3920 into the chamber 3975. The fluidic material 3980
25 then passes out of the chamber 3975, through the fluid passage 3945, and into the annular region 3970. In a preferred embodiment, the fluidic material 3980 is pumped into the chamber 3970 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency. In a preferred embodiment, the fluidic material 3980
30 comprises a hardenable fluidic sealing material in order to form a hardened outer annular member around the expanded tubular member 3925.

As illustrated in FIG. 24C, at some later point in the process, a ball 3985, plug or other similar device, is introduced into the pumped fluidic material 3980. In a preferred embodiment, the ball 3985 mates with and seals off the inlet 3965 of the fluid passage 3920. In this manner, the chamber 3970 is fluidically isolated from the chamber 3975.

As illustrated in FIG. 24D, after placement of the ball 3985 in the inlet 3965 of the fluid passage 3920, a fluidic material 3990 is pumped into the chamber 3970. The fluidic material is preferably pumped into the chamber 3970 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to provide optimal operating efficiency. The fluidic material 3990 may comprise any number of conventional commercially available materials such as, for example, water, drilling mud, cement, epoxy, or slag mix. In a preferred embodiment, the fluidic material 3990 comprises a non-hardenable fluidic material in order to maximize operational efficiency.

Continued pumping of the fluidic material 3990 increases fluidic material 3980 increases the operating pressure within the chamber 3970. The increased operating pressure in the chamber 3970 then causes the mandrel 3915 to extrude the mandrel launcher 3910 and tubular member 3925 off of the conical face of the mandrel 3915. The extrusion of the mandrel launcher 3910 and tubular member 3925 off of the conical face of the mandrel 3915 causes the mandrel launcher 3910 and tubular member 3925 to expand in the radial direction. Continued pumping of the fluidic material 3990 preferably causes the entire length of the tubular member 3925 to expand in the radial direction.

In a preferred embodiment, the pumping rate and pressure of the fluidic material 3990 is reduced during the latter stages of the extrusion process in order to minimize shock to the apparatus 3900. In a preferred embodiment, the apparatus 3900 includes shock absorbers for absorbing the shock caused by the completion of the extrusion process. In a preferred embodiment, the extrusion process causes the mandrel 3915 to move in an axial direction 3995.

As illustrated in FIG. 24E, in a preferred embodiment, upon the completion of the extrusion process, the support member 3905, packer 3910, first fluid conduit 3915, annular seal 3930, second fluid conduit 3935, mandrel 3945, and mandrel

launcher 3950 are removed from the wellbore 3980. In a preferred embodiment, the resulting new section of wellbore casing includes the preexisting wellbore casing 3975, the expanded tubular member 3925, the slips 3930, the seals 3935, the shoe 3940, and an outer annular layer 4000 of hardened fluidic material.

5 In an alternative embodiment, the apparatus 3900 is used to repair a preexisting wellbore casing or pipeline. In this alternative embodiment, both ends of the tubular member 3955 preferably include slips 3960 and seals 3965.

In an alternative embodiment, the apparatus 3900 is used to form a tubular structural support for a building or offshore structure.

10 Referring to FIGS. 25 and 26, the optimal relationship between the angle of attack of an expansion mandrel and the minimally required propagation pressure during the expansion of a tubular member will now be described. As illustrated in FIG. 25, during the radial expansion of a tubular member 4100 by an expansion mandrel 4105, the expansion mandrel 4105 is displaced in the axial
15 direction. The angle of attack α of the conical surface 4110 of the expansion mandrel 4105 directly affects the required propagation pressure P_{PR} necessary to radially expand the tubular member 4100. Referring to FIG. 26, for typical grades of materials and typical geometries, the propagation pressure P_{PR} is minimized for an angle of attack of approximately 25 degrees. Furthermore, the optimal range
20 of the angle of attack α ranges from about 10 to 30 degrees in order to minimize the range of required minimum propagation pressure P_{PR} .

Referring to FIG. 27, an embodiment of an expandable threaded connection 4300 will now be described. The expandable threaded connection 4300 preferably includes a first tubular member 4305, a second tubular member 4310, a threaded
25 connection 4315, an O-ring groove 4320, and an O-ring 4325.

The first tubular member 4305 includes an inside wall 4330 and an outside wall 4335. The first tubular member 4305 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4310 includes an inside wall 4340 and an outside wall 4345. The second
30 tubular member 4310 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4305 and 4310, may comprise any number of conventional commercially available members. In a preferred embodiment, the inside and outside diameters of the first and second tubular members, 4305 and 4310, are substantially equal. In this manner, the burst strength of the tubular members, 4305 and 4310, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4315 may comprise any number of conventional threaded connections suitable for use with tubular members. In a preferred embodiment, the threaded connection 4315 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4305 to the second tubular member 4310 is optimized.

The O-ring groove 4320 is preferably provided in the threaded portion of the interior wall 4340 of the second tubular member 4310. The O-ring groove 4320 is preferably adapted to receive and support one or more O-rings. The volumetric size of the O-ring groove 4320 is preferably selected to permit the O-ring 4325 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4345 of the second tubular member 4310 during and upon the completion of the radial expansion process is minimized.

The O-ring 4325 is supported by the O-ring groove 4320. The O-ring 4325 optimally ensures that a fluid-tight seal is maintained between the first tubular member 4305 and the second tubular member 4310 throughout and upon the completion of the radial expansion process.

Referring to FIG. 28, an alternative embodiment of an expandable threaded connection 4500 will now be described. The expandable threaded connection 4500 includes a first tubular member 4505, a second tubular member 4510, a threaded connection 4515, an O-ring groove 4520, and an O-ring 4525.

The first tubular member 4505 includes an inside wall 4530 and an outside wall 4535. The first tubular member 4305 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4510 includes an inside wall 4540 and an outside wall 4545. The second

tubular member 4510 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4505 and 4510, may comprise any number of conventional commercially available members. In a preferred embodiment, the inside and outside diameters of the first and second tubular members, 4505 and 4510, are substantially equal. In this manner, the burst strength of the tubular members, 4505 and 4510, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

10 The threaded connection 4515 may comprise any number of conventional threaded connections suitable for use with tubular members. In a preferred embodiment, the threaded connection 4515 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4505 to the second tubular member 4510 is optimized.

15 The O-ring groove 4520 is preferably provided in the threaded portion of the interior wall 4540 of the second tubular member 4510 immediately adjacent to an end portion of the threaded connection 4515. In this manner, the sealing effect provided by the O-ring 4525 is optimized. The O-ring groove 4520 is preferably adapted to receive and support one or more O-rings. The volumetric size of the O-ring groove 4520 is preferably selected to permit the O-ring 4525 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4545 of the second tubular member 4510 during and upon the completion of the radial expansion process is minimized.

25 The O-ring 4525 is supported by the O-ring groove 4520. The O-ring 4525 optimally ensures that a fluid-tight seal is maintained between the first tubular member 4505 and the second tubular member 4510 throughout and upon the completion of the radial expansion process.

Referring to FIG. 29, an alternative embodiment of an expandable threaded connection 4700 will now be described. The expandable threaded connection 4700 includes a first tubular member 4705, a second tubular member 4710, a threaded

connection 4715, an O-ring groove 4720, a first O-ring 4725, and a second O-ring 4730.

The first tubular member 4705 includes an inside wall 4735 and an outside wall 4740. The first tubular member 4705 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4710 includes an inside wall 4745 and an outside wall 4750. The second tubular member 4710 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4705 and 4710, may comprise any number of conventional commercially available members. In a preferred embodiment, the inside and outside diameters of the first and second tubular members, 4705 and 4710, are substantially equal. In this manner, the burst strength of the tubular members, 4705 and 4710, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4715 may comprise any number of conventional threaded connections suitable for use with tubular members. In a preferred embodiment, the threaded connection 4715 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4705 to the second tubular member 4710 is optimized.

The O-ring groove 4720 is preferably provided in the threaded portion of the interior wall 4745 of the second tubular member 4710 immediately adjacent to an end portion of the threaded connection 4715. In this manner, the sealing effect provided by the O-rings, 4725 and 4730, is optimized. The O-ring groove 4720 is preferably adapted to receive and support a plurality of O-rings. The volumetric size of the O-ring groove 4720 is preferably selected to permit the O-rings, 4725 and 4730, to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4750 of the second tubular member 4710 during and upon the completion of the radial expansion process is minimized.

The O-rings, 4725 and 4730, are supported by the O-ring groove 4720. The pair of O-rings, 4725 and 4730, optimally ensure that a fluid-tight seal is

maintained between the first tubular member 4705 and the second tubular member 4710 throughout and upon the completion of the radial expansion process. In particular, the use of a pair of adjacent O-rings provides redundancy in the seal between the first tubular member 4705 and the second tubular member 4710.

5 Referring to FIG. 30, an alternative embodiment of an expandable threaded connection 4900 will now be described. The expandable threaded connection 4900 includes a first tubular member 4905, a second tubular member 4910, a threaded connection 4915, a first O-ring groove 4920, a second O-ring groove 4925, a first O-ring 4930, and a second O-ring 4935.

10 The first tubular member 4905 includes an inside wall 4940 and an outside wall 4945. The first tubular member 4905 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4910 includes an inside wall 4950 and an outside wall 4955. The second tubular member 4910 preferably comprises an annular member having a
15 substantially constant wall thickness.

The first and second tubular members, 4905 and 4910, may comprise any number of conventional commercially available tubular members. In a preferred embodiment, the inside and outside diameters of the first and second tubular members, 4905 and 4910, are substantially equal. In this manner, the burst
20 strength of the tubular members, 4905 and 4910, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4915 may comprise any number of conventional threaded connections suitable for use with tubular members. In a preferred
25 embodiment, the threaded connection 4915 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4905 to the second tubular member 4910 is optimized.

The first O-ring groove 4920 is preferably provided in the threaded portion of the interior wall 4950 of the second tubular member 4910 that is separated from
30 an end portion of the threaded connection 4915. In this manner, the sealing effect provided by the O-rings, 4930 and 4935, is optimized. The first O-ring groove 4920 is preferably adapted to receive and support one more O-rings. The

volumetric size of the first O-ring groove 4920 is preferably selected to permit the O-ring 4930 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4955 of the second tubular member 4910 during and upon the completion of the radial expansion process is minimized.

The second O-ring groove 4925 is preferably provided in the threaded portion of the interior wall 4950 of the second tubular member 4910 that is immediately adjacent to an end portion of the threaded connection 4915. In this manner, the sealing effect provided by the O-rings, 4930 and 4935, is optimized.

10 The second O-ring groove 4925 is preferably adapted to receive and support one more O-rings. The volumetric size of the second O-ring groove 4925 is preferably selected to permit the O-ring 4935 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4955 of the second tubular member 4910 during and upon the completion of the radial expansion process is minimized.

The O-rings, 4930 and 4935, are supported by the O-ring grooves, 4920 and 4925. The use of a pair of O-rings, 4930 and 4935, that are axially separated optimally ensures that a fluid-tight seal is maintained between the first tubular member 4905 and the second tubular member 4910 throughout and upon the completion of the radial expansion process. In particular, the use of a pair of O-rings provides redundancy in the seal between the first tubular member 4905 and the second tubular member 4910.

In a preferred embodiment, the expandable threaded connections 4300, 4500, 4700, and/or 4900 are used in combination with one or more of the embodiments illustrated in FIGS. 1-24E in order to optimally expand a plurality of tubular members coupled end to end using the expandable threaded connections 4300, 4500, 4700 and/or 4900.

Referring to FIG. 31, the lubrication of the interface between an expansion mandrel and a tubular member during the radial expansion process will now be described. As illustrated in FIG. 31, during the radial expansion process, an expansion cone 5000 radially expands a tubular member 5005 by moving in an axial direction 5010 relative to the tubular member 5005. The interface between

the outer surface 5010 of the tapered portion 5015 of the expansion cone 5000 and the inner surface 5020 of the tubular member 5005 includes a leading edge portion 5025 and a trailing edge portion 5030.

During the radial expansion process, the leading edge portion 5025 is
5 preferably lubricated by the presence of lubricating fluids provided ahead of the expansion cone 5000. However, because the radial clearance between the expansion cone 5000 and the tubular member 5005 in the trailing edge portion 5030 during the radial expansion process is typically extremely small, and the operating contact pressures between the tubular member 5005 and the expansion
10 mandrel 5000 are extremely high, the quantity of lubricating fluid provided to the trailing edge portion 5030 is typically greatly reduced. In typical radial expansion operations, this reduction in lubrication in the trailing edge portion 5030 increases the forces required to radially expand the tubular member 5005.

Referring to FIG. 32, an embodiment of a system for lubricating the
15 interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 32, an expansion cone 5100, having a front end 5100a and a rear end 5100b, includes a tapered portion 5105 having an outer surface 3110, one or more circumferential grooves 5115a and 5115b, and one or more internal flow passages 5120a and 5120b.

20 In a preferred embodiment, the circumferential grooves 5115 are fluidically coupled to the internal flow passages 5120. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5100a of the expansion cone 5100 into the circumferential grooves 5115. Thus, the trailing edge portion of the interface between the expansion cone 5100
25 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. In a preferred embodiment, the lubricating fluids are injected into the internal flow passages 5120 using a fluid conduit that is coupled to the tapered end 5105 of the expansion cone 5100. Alternatively, lubricating fluids are provided for the internal
30 flow passages 5120 using a supply of lubricating fluids provided adjacent to the front 5100a of the expansion cone 5100.

In a preferred embodiment, the expansion cone 5100 includes a plurality of circumferential grooves 5115. In a preferred embodiment, the cross sectional area of the circumferential grooves 5115 range from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface
5 between the expansion cone 5100 and a tubular member during the radial expansion process. In a preferred embodiment, the expansion cone 5100 includes circumferential grooves 5115 concentrated about the axial midpoint of the tapered portion 5105 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during
10 the radial expansion process. In a preferred embodiment, the circumferential grooves 5115 are equally spaced along the trailing edge portion of the expansion cone 5100 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process.

15 In a preferred embodiment, the expansion cone 5100 includes a plurality of flow passages 5120 coupled to each of the circumferential grooves 5115. In a preferred embodiment, the cross-sectional area of the flow passages 5120 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a
20 tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5115 is greater than the cross sectional area of the flow passage 5120 in order to minimize resistance to fluid flow.

Referring to FIG. 33, another embodiment of a system for lubricating the
25 interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 33, an expansion cone 5200, having a front end 5200a and a rear end 5200b, includes a tapered portion 5205 having an outer surface 5210, one or more circumferential grooves 5215a and 5215b, and one or more axial grooves 5220a and 5220b.

30 In a preferred embodiment, the circumferential grooves 5215 are fluidically coupled to the axial grooves 5220. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5200a

of the expansion cone 5200 into the circumferential grooves 5215. Thus, the trailing edge portion of the interface between the expansion cone 5200 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. In a preferred embodiment, the axial grooves 5220 are provided with lubricating fluid using a supply of lubricating fluid positioned proximate the front end 5200a of the expansion cone 5200. In a preferred embodiment, the circumferential grooves 3215 are concentrated about the axial midpoint of the tapered portion 5205 of the expansion cone 5200 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5215 are equally spaced along the trailing edge portion of the expansion cone 5200 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5200 includes a plurality of circumferential grooves 5215. In a preferred embodiment, the cross sectional area of the circumferential grooves 5215 range from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5200 includes a plurality of axial grooves 5220 coupled to each of the circumferential grooves 5215. In a preferred embodiment, the cross sectional area of the axial grooves 5220 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5215 is greater than the cross sectional area of the axial grooves 5220 in order to minimize resistance to fluid flow. In a preferred embodiment, the axial grooves 5220 are spaced apart in the circumferential direction by at least about 3 inches in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 34, another embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 34, an expansion cone 5300, having a front end 5300a and a rear end 5300b, includes a tapered portion 5305
5 having an outer surface 5310, one or more circumferential grooves 5315a and 5315b, and one or more internal flow passages 5320a and 5320b.

In a preferred embodiment, the circumferential grooves 5315 are fluidically coupled to the internal flow passages 5320. In this manner, during the radial expansion process, lubricating fluids are transmitted from the areas in front of the
10 front 5300a and/or behind the rear 5300b of the expansion cone 5300 into the circumferential grooves 5315. Thus, the trailing edge portion of the interface between the expansion cone 5300 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. Furthermore, the lubricating fluids also
15 preferably pass to the area in front of the expansion cone. In this manner, the area adjacent to the front 5300a of the expansion cone 5300 is cleaned of foreign materials. In a preferred embodiment, the lubricating fluids are injected into the internal flow passages 5320 by pressurizing the area behind the rear 5300b of the expansion cone 5300 during the radial expansion process.

20 In a preferred embodiment, the expansion cone 5300 includes a plurality of circumferential grooves 5315. In a preferred embodiment, the cross sectional area of the circumferential grooves 5315 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ respectively, in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during
25 the radial expansion process. In a preferred embodiment, the expansion cone 5300 includes circumferential grooves 5315 that are concentrated about the axial midpoint of the tapered portion 5305 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process. In a preferred embodiment,
30 the circumferential grooves 5315 are equally spaced along the trailing edge portion of the expansion cone 5300 in order to optimally provide lubrication to the trailing

edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5300 includes a plurality of flow passages 5320 coupled to each of the circumferential grooves 5315. In a preferred embodiment, the flow passages 5320 fluidically couple the front end 5300a and the rear end 5300b of the expansion cone 5300. In a preferred embodiment, the cross-sectional area of the flow passages 5320 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5315 is greater than the cross-sectional area of the flow passages 5320 in order to minimize resistance to fluid flow.

Referring to FIG. 35, an embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 35, an expansion cone 5400, having a front end 5400a and a rear end 5400b, includes a tapered portion 5405 having an outer surface 5410, one or more circumferential grooves 5415a and 5415b, and one or more axial grooves 5420a and 5420b.

In a preferred embodiment, the circumferential grooves 5415 are fluidically coupled to the axial grooves 5420. In this manner, during the radial expansion process, lubricating fluids are transmitted from the areas in front of the front 5400a and/or behind the rear 5400b of the expansion cone 5400 into the circumferential grooves 5415. Thus, the trailing edge portion of the interface between the expansion cone 5400 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. Furthermore, in a preferred embodiment, pressurized lubricating fluids pass from the fluid passages 5420 to the area in front of the front 5400a of the expansion cone 5400. In this manner, the area adjacent to the front 5400a of the expansion cone 5400 is cleaned of foreign materials. In a preferred embodiment, the lubricating fluids are injected into the internal flow passages 5420 by pressurizing the area behind the rear 5400b expansion cone 5400 during the radial expansion process.

In a preferred embodiment, the expansion cone 5400 includes a plurality of circumferential grooves 5415. In a preferred embodiment, the cross sectional area of the circumferential grooves 5415 range from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface
5 between the expansion cone 5400 and a tubular member during the radial expansion process. In a preferred embodiment, the expansion cone 5400 includes circumferential grooves 5415 that are concentrated about the axial midpoint of the tapered portion 5405 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member
10 during the radial expansion process. In a preferred embodiment, the circumferential grooves 5415 are equally spaced along the trailing edge portion of the expansion cone 5400 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process.

15 In a preferred embodiment, the expansion cone 5400 includes a plurality of axial grooves 5420 coupled to each of the circumferential grooves 5415. In a preferred embodiment, the axial grooves 5420 fluidically couple the front end and the rear end of the expansion cone 5400. In a preferred embodiment, the cross sectional area of the axial grooves 5420 range from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$,
20 respectively, in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5415 is greater than the cross sectional area of the axial grooves 5420 in order to minimize resistance to fluid flow. In a preferred
25 embodiment, the axial grooves 5420 are spaced apart in the circumferential direction by at least about 3 inches in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 36, another embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion
30 process will now be described. As illustrated in FIG. 36, an expansion cone 5500, having a front end 5500a and a rear end 5500b, includes a tapered portion 5505

having an outer surface 5510, one or more circumferential grooves 5515a and 5515b, and one or more axial grooves 5520a and 5520b.

In a preferred embodiment, the circumferential grooves 5515 are fluidically coupled to the axial grooves 5520. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5500a of the expansion cone 5500 into the circumferential grooves 5515. Thus, the trailing edge portion of the interface between the expansion cone 5500 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. In a preferred embodiment, the lubricating fluids are injected into the axial grooves 5520 using a fluid conduit that is coupled to the tapered end 3205 of the expansion cone 3200.

In a preferred embodiment, the expansion cone 5500 includes a plurality of circumferential grooves 5515. In a preferred embodiment, the cross sectional area of the circumferential grooves 5515 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5500 and a tubular member during the radial expansion process. In a preferred embodiment, the expansion cone 5500 includes circumferential grooves 5515 that are concentrated about the axial midpoint of the tapered portion 5505 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5500 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5515 are equally spaced along the trailing edge portion of the expansion cone 5500 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5500 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5500 includes a plurality of axial grooves 5520 coupled to each of the circumferential grooves 5515. In a preferred embodiment, the axial grooves 5520 intersect each of the circumferential grooves 5515 at an acute angle. In a preferred embodiment, the cross sectional area of the axial grooves 5520 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between

the expansion cone 5500 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5515 is greater than the cross sectional area of the axial grooves 5520. In a preferred embodiment, the axial grooves 5520 are spaced apart in the circumferential direction by at least about 3 inches in order to optimally provide lubrication during the radial expansion process. In a preferred embodiment, the axial grooves 5520 intersect the longitudinal axis of the expansion cone 5500 at a larger angle than the angle of attack of the tapered portion 5505 in order to optimally provide lubrication during the radial expansion process.

10 Referring to FIG. 37, another embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 37, an expansion cone 5600, having a front end 5600a and a rear end 5600b, includes a tapered portion 5605 having an outer surface 5610, a spiral circumferential groove 5615, and one or more internal flow passages 5620.

In a preferred embodiment, the circumferential groove 5615 is fluidically coupled to the internal flow passage 5620. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5600a of the expansion cone 5600 into the circumferential groove 5615. Thus, the trailing edge portion of the interface between the expansion cone 5600 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. In a preferred embodiment, the lubricating fluids are injected into the internal flow passage 5620 using a fluid conduit that is coupled to the tapered end 5605 of the expansion cone 5600.

In a preferred embodiment, the expansion cone 5600 includes a plurality of spiral circumferential grooves 5615. In a preferred embodiment, the cross sectional area of the circumferential groove 5615 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5600 and a tubular member during the radial expansion process. In a preferred embodiment, the expansion cone 5600 includes circumferential grooves 5615 that are concentrated about the axial

midpoint of the tapered portion 5605 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5600 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5615 are equally spaced along the trailing edge portion
5 of the expansion cone 5600 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5600 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5600 includes a plurality of flow passages 5620 coupled to each of the circumferential grooves 5615. In a
10 preferred embodiment, the cross-sectional area of the flow passages 5620 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5600 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential groove 5615 is greater than the cross
15 sectional area of the flow passage 5620 in order to minimize resistance to fluid flow.

Referring to FIG. 38, another embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 38, an expansion cone 5700,
20 having a front end 5700a and a rear end 5700b, includes a tapered portion 5705 having an outer surface 5710, a spiral circumferential groove 5715, and one or more axial grooves 5720a, 5720b and 5720c.

In a preferred embodiment, the circumferential groove 5715 is fluidically coupled to the axial grooves 5720. In this manner, during the radial expansion
25 process, lubricating fluids are transmitted from the area ahead of the front 5700a of the expansion cone 5700 into the circumferential groove 5715. Thus, the trailing edge portion of the interface between the expansion cone 5700 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. In
30 a preferred embodiment, the lubricating fluids are injected into the axial grooves 5720 using a fluid conduit that is coupled to the tapered end 5705 of the expansion cone 5700.

In a preferred embodiment, the expansion cone 5700 includes a plurality of spiral circumferential grooves 5715. In a preferred embodiment, the cross sectional area of the circumferential grooves 5715 range from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5700 and a tubular member during the radial expansion process. In a preferred embodiment, the expansion cone 5700 includes circumferential grooves 5715 concentrated about the axial midpoint of the tapered portion 5705 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5700 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5715 are equally spaced along the trailing edge portion of the expansion cone 5700 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5700 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5700 includes a plurality of axial grooves 5720 coupled to each of the circumferential grooves 5715. In a preferred embodiment, the cross sectional area of the axial grooves 5720 range from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5700 and a tubular member during the radial expansion process. In a preferred embodiment, the axial grooves 5720 intersect the circumferential grooves 5715 in a perpendicular manner. In a preferred embodiment, the cross sectional area of the circumferential groove 5715 is greater than the cross sectional area of the axial grooves 5720 in order to minimize resistance to fluid flow. In a preferred embodiment, the circumferential spacing of the axial grooves is greater than about 3 inches in order to optimally provide lubrication during the radial expansion process. In a preferred embodiment, the axial grooves 5720 intersect the longitudinal axis of the expansion cone at an angle greater than the angle of attack of the tapered portion 5705 in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 39, a preferred embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion

process will now be described. As illustrated in FIG. 39, an expansion cone 5800, having a front end 5800a and a rear end 5800b, includes a tapered portion 5805 having an outer surface 5810, a circumferential groove 5815, a first axial groove 5820, and one or more second axial grooves 5825a, 5825b, 5825c and 5825d.

5 In a preferred embodiment, the circumferential groove 5815 is fluidically coupled to the axial grooves 5820 and 5825. In this manner, during the radial expansion process, lubricating fluids are preferably transmitted from the area behind the back 5800b of the expansion cone 5800 into the circumferential groove 5815. Thus, the trailing edge portion of the interface between the expansion cone
10 5800 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. In a preferred embodiment, the lubricating fluids are injected into the first axial groove 5820 by pressurizing the region behind the back 5800b of the expansion cone 5800. In a preferred embodiment, the lubricant is further
15 transmitted into the second axial grooves 5825 where the lubricant preferably cleans foreign materials from the tapered portion 5805 of the expansion cone 5800.

In a preferred embodiment, the expansion cone 5800 includes a plurality of circumferential grooves 5815. In a preferred embodiment, the cross sectional area of the circumferential groove 5815 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in
20 order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the radial expansion process. In a preferred embodiment, the expansion cone 5800 includes circumferential grooves 5815 concentrated about the axial midpoint of the tapered portion 5805 in order to optimally provide lubrication to the trailing edge portion
25 of the interface between the expansion cone 5800 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5815 are equally spaced along the trailing edge portion of the expansion cone 5800 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the
30 radial expansion process.

In a preferred embodiment, the expansion cone 5800 includes a plurality of first axial grooves 5820 coupled to each of the circumferential grooves 5815. In a

preferred embodiment, the first axial grooves 5820 extend from the back 5800b of the expansion cone 5800 and intersect the circumferential groove 5815. In a preferred embodiment, the cross sectional area of the first axial groove 5820 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide lubrication to the

5 trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the radial expansion process. In a preferred embodiment, the first axial groove 5820 intersects the circumferential groove 5815 in a perpendicular manner. In a preferred embodiment, the cross sectional area of the circumferential groove 5815 is greater than the cross sectional area of the first

10 axial groove 5820 in order to minimize resistance to fluid flow. In a preferred embodiment, the circumferential spacing of the first axial grooves 5820 is greater than about 3 inches in order to optimally provide lubrication during the radial expansion process.

In a preferred embodiment, the expansion cone 5800 includes a plurality of

15 second axial grooves 5825 coupled to each of the circumferential grooves 5815. In a preferred embodiment, the second axial grooves 5825 extend from the front 5800a of the expansion cone 5800 and intersect the circumferential groove 5815. In a preferred embodiment, the cross sectional area of the second axial grooves 5825 ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$ in order to optimally provide

20 lubrication to the trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the radial expansion process. In a preferred embodiment, the second axial grooves 5825 intersect the circumferential groove 5815 in a perpendicular manner. In a preferred embodiment, the cross sectional area of the circumferential groove 5815 is greater than the cross sectional area of

25 the second axial grooves 5825 in order to minimize resistance to fluid flow. In a preferred embodiment, the circumferential spacing of the second axial grooves 5825 is greater than about 3 inches in order to optimally provide lubrication during the radial expansion process. In a preferred embodiment, the second axial grooves 5825 intersect the longitudinal axis of the expansion cone 5800 at an angle

30 greater than the angle of attack of the tapered portion 5805 in order to optimally provide lubrication during the radial expansion process.

Referring to Fig. 40, in a preferred embodiment, the first axial groove 5820 includes a first portion 5905 having a first radius of curvature 5910, a second portion 5915 having a second radius of curvature 5920, and a third portion 5925 having a third radius of curvature 5930. In a preferred embodiment, the radius of curvatures, 5910, 5920 and 5930 are substantially equal. In an exemplary embodiment, the radius of curvatures, 5910, 5920 and 5930 are all substantially equal to 0.0625 inches.

Referring to Fig. 41, in a preferred embodiment, the circumferential groove 5815 includes a first portion 6005 having a first radius of curvature 6010, a second portion 6015 having a second radius of curvature 6020, and a third portion 6025 having a third radius of curvature 6030. In a preferred embodiment, the radius of curvatures, 6010, 6020 and 6030 are substantially equal. In an exemplary embodiment, the radius of curvatures, 6010, 6020 and 6030 are all substantially equal to 0.125 inches.

Referring to Fig. 42, in a preferred embodiment, the second axial groove 5825 includes a first portion 6105 having a first radius of curvature 6110, a second portion 6115 having a second radius of curvature 6120, and a third portion 6125 having a third radius of curvature 6130. In a preferred embodiment, the first radius of curvature 6110 is greater than the third radius of curvature 6130. In an exemplary embodiment, the first radius of curvature 6110 is equal to 0.5 inches, the second radius of curvature 6120 is equal to 0.0625 inches, and the third radius of curvature 6130 is equal to 0.125 inches.

Referring to Fig. 43, an embodiment of an expansion mandrel 6200 includes an internal flow passage 6205 having an insert 6210 including a flow passage 6215. In a preferred embodiment, the cross sectional area of the flow passage 6215 is less than the cross sectional area of the flow passage 6215. More generally, in a preferred embodiment, a plurality of inserts 6210 are provided, each with different sizes of flow passages 6215. In this manner, the flow passage 6215 is machined to a standard size, and the lubricant supply is varied by using different sized inserts 6210. In a preferred embodiment, the teachings of the expansion mandrel 6200 are incorporated into the expansion mandrels 5100, 5300, and 5600.

Referring to Fig. 44, in a preferred embodiment, the insert 6210 includes a filter 6305 for filtering particles and other foreign materials from the lubricant that passes into the flow passage 6205. In this manner, the foreign materials are prevented from clogging the flow passage 6205 and other flow passages within the expansion mandrel 6200.

In a preferred embodiment, the one or more of the lubrication systems and elements of the mandrels 5100, 5200, 5300, 5400, 5500, 5600, 5700, 5800 and/or 5900 are incorporated into the methods and apparatus for expanding tubular members described above with reference to FIGS. 1-30. In this manner, the amount of force required to radially expand a tubular member in the formation and/or repair of a wellbore casing, pipeline, or structural support is significantly reduced. Furthermore, the increased lubrication provided to the trail edge portion of the mandrel greatly reduces the amount of galling or seizure caused by the interface between the mandrel and the tubular member during the radial expansion process thereby permitting larger continuous sections of tubulars to be radially expanded in a single continuous operation. Thus, use of the mandrels 5100, 5200, 5300, 5400, 5500, 5600, 5700, 5800 and/or 5900 reduces the operating pressures required for radial expansion and thereby reduces the sizes of the required hydraulic pumps and related equipment. In addition, failure, bursting, and/or buckling of tubular members during the radial expansion process is significantly reduced, and the success ratio of the radial expansion process is greatly increased.

In laboratory tests, a regular expansion cone, without any lubrication grooves and flow passages, and the expansion cone 5100 were both used to radially expand identical coiled tubular members, each having an outside diameter of 3 ½ inches. The following tables summarizes the results of this laboratory test:

LUBRICATING FLUID	REGULAR EXPANSION CONE	EXPANSION CONE 5100
	FORCE REQUIRED TO EXPAND TUBULAR MEMBER	
PHPA Mud alone	78,000 lbf	72,000 lbf

PHPA Mud + 7% Lubricant Blend	48,000 lbf	46,000 lbf
100% Lubricant Blend	68,000 lbf	48,000 lbf

Where: PHPA Mud refers to a drilling mud mixture available from Baroid.

5 PHPA Mud + 7 % Lubricant Blend refers to a mixture of 93% PHPA Mud and 7% mixture of TorqTrim III, EP Mudlib, and DrillN-Slid available from Baroid.

100% Lubricant Blend refers to a mixture of TorqTrim III, EP Mudlib, and DrillN-Slid available from Baroid.

10 Thus, in an exemplary embodiment, the use of the expansion cone 5100 reduced the amount of force required to radially expand a tubular member by as much as 30%. This reduction in the required force translates to a corresponding reduction in the overall energy requirements as well as a reduction in the size of required operating equipment such as, for example, hydraulic pumping equipment.

15 During the course of a typical expansion operation, this results in tremendous cost savings to the operator.

In a preferred embodiment, the lubricating fluids used with the mandrels 5100, 5200, 5300, 5400, 5500, 5600, 5700, 5800 and 5900 for expanding tubular members have viscosities ranging from about 1 to 10,000 centipoise in order to

20 optimize the injection of the lubricating fluids into the circumferential grooves of the mandrels during the radial expansion process.

In a preferred embodiment, prior to placement in a wellbore, the outer surfaces of the apparatus for expanding tubular members described above with reference to FIGS. 1-30 are coated with a lubricating fluid to facilitate their

25 placement the wellbore and reduce surge pressures. In a preferred embodiment, the lubricating fluid comprises BARO-LUB GOLD-SEAL™ brand drilling mud

lubricant, available from Baroid Drilling Fluids, Inc. In this manner, the insertion of the apparatus into a wellbore, pipeline or other opening is optimized.

Referring to FIG. 45, a preferred embodiment of an expandible tubular 6400 for use in forming and/or repairing a wellbore casing, pipeline, or foundation support will now be described. In a preferred embodiment, the expandible tubular 6400 includes a wall thickness T.

In a preferred embodiment, the wall thickness T is substantially constant throughout the expandible tubular 6400. In a preferred embodiment, the variation in the wall thickness T about the circumference of the tubular member 6400 is less than about 8 % in order to optimally provide an expandible tubular 6400 having a substantially constant hoop yield strength.

In a preferred embodiment, the material composition of and the manufacturing processes used in forming the expandible tubular 6400 are selected to provide a hoop yield strength that varies less than about 10 % about the circumference of the tubular member 6400 in order to optimally provide consistent geometries in the expandible tubular 6400 after radial expansion.

In a preferred embodiment, the expandible tubular 6400 includes structural imperfections such as, for example, voids, foreign material, cracks, of less than about 5 % of the specified wall thickness T in order to optimize the radial expansion of the expandible tubular member 6400. In a preferred embodiment, each expandible tubular 6400 is tested for the presence of such defects using nondestructive testing methods in accordance with industry standard API SR2.

In a preferred embodiment, a representative sample of a selected group of tubular members 6400 are flared at one end using a conventional industry standard tubular flaring method, such as, for example the method disclosed in ASTM A450. As illustrated in Fig. 46, in a preferred embodiment, the walls of the flared end of the tubular member 6400 do not exhibit any necking for increases in the interior diameter of the flared end 6405 of the tubular member 6400 ranging from 0 to about 25%. As illustrated in Fig. 47, in a preferred embodiment, the flared end of the tubular member 6400 does not fail for increases in the interior diameter of the flared end of the tubular members 6400 ranging from 0 to at least about 30%. In this manner, a selected group of tubular members 6400 are

optimally selected for both necking and ductility properties subsequent to radial expansion.

Referring now to FIG. 48, a preferred embodiment of an expandable tubular member 6500 will now be described. The tubular member 6500 preferably includes a tubular body 6505 having an interior region 6510, an exterior surface 6515, a first end 6520 including a first expandable threaded connection 6525, an intermediate portion 6530, and a second end 6535 including a second expandable threaded connection 6540. The tubular member 6500 further preferably includes a first sealing member 6545, an intermediate sealing member 6550, and a second sealing member 6555. In a preferred embodiment, the tubular members 210, 715, 915, 1110, 1310, 1520, 1530, 1535, 1620, 1715, 1970, 2155, 2375, 2560, 2790, 3075, 3525, 3755, 3925, 4100, 5005, and 6400, described above with reference to FIGS. 1-47 comprise the tubular member 6500 in order to optimally provide an expanded tubular member for use in forming and/or repairing a wellbore casing, pipeline, or structural support. In a preferred embodiment, tubular members 210, 715, 915, 1110, 1310, 1520, 1530, 1535, 1620, 1715, 1970, 2155, 2375, 2560, 2790, 3075, 3525, 3755, 3925, 4100, 5005, and 6400, described above with reference to FIGS. 1-47, having wall thicknesses greater than about 0.25 inches are used for radial expansion operations, and the tubular member 6500 is used for all other radial expansion operations.

The tubular body 6505 of the tubular member 6500 preferably has a substantially annular cross section. The tubular body 6505 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or L83, J55, or P110 API casing. In a preferred embodiment, the tubular body 6505 of the tubular member 6500 is selected using the teachings for selecting expandable tubular members described above with reference to FIGS. 45-47.

The interior region 6510 of the tubular body 6505 preferably has a substantially circular cross section. The interior region 6510 of the tubular body 6505 preferably includes a first inside diameter D_1 , an intermediate inside diameter D_{INT} , and a second inside diameter D_2 . In a preferred embodiment, the first and second inside diameters, D_1 and D_2 , are substantially equal. In a

preferred embodiment, the first and second inside diameters, D_1 and D_2 , are greater than the intermediate inside diameter D_{INT} .

The first end 6520 of the tubular body 6505 is coupled to the intermediate portion 6530 of the tubular body. The first end 6520 of the tubular body 6505
5 preferably includes the first expandable threaded connection 6525 and the first sealing member 6545. In a preferred embodiment, the outside diameter of the first end 6520 of the tubular body 6505 is greater than the outside diameter of the intermediate portion 6530 of the tubular body 6530. In this manner, the intermediate sealing member 6550 is optimally protected during placement of the
10 tubular member 6500 within a wellbore casing 6560. In a preferred embodiment, the outside diameter of the first end 6520 of the tubular body 6505 is substantially equal to the outside diameter of the second end 6535 of the tubular body 6505. In this manner, the intermediate sealing member 6550 is optimally protected during placement of the tubular member 6500 within the wellbore casing 6560. In a
15 preferred embodiment, the outside diameter of the first end 6520 of the tubular member 6505 is adapted to permit insertion of the tubular member 6500 into the typical range of wellbore casings. The first end 6520 of the tubular member 6505 includes a wall thickness t_1 .

The first expandable threaded connection 6525 is coupled to the first end
20 6520 of the tubular body 6505. The first expandable threaded connection 6525 may comprise any number of conventional commercially available threaded connections suitable for radial expansion. In a preferred embodiment, the first expandable threaded connection 6525 is provided in accordance with the teachings of the expandable threaded connections, 4300, 4500, 4700 and 4900, described
25 above with reference to FIGS. 27-30. In a preferred embodiment, the first expandable threaded connection 6525 is adapted to mate with an adjacent second expandable threaded connection provided in an adjacent tubular member 6500. In this manner, a plurality of tubular members 6500 may be coupled end to end.

The intermediate portion 6530 of the tubular body 6505 is coupled to the
30 first end 6520 of the tubular body 6505 and the second end 6535 of the tubular body 6505. The intermediate portion 6530 of the tubular body preferably includes the intermediate sealing member 6550. In a preferred embodiment, the outside

diameter of the intermediate portion 6520 of the tubular body is less than the outside diameter of the first and second ends, 6520 and 6535, of the tubular body 6530. In this manner, the intermediate sealing member 6550 is optimally protected during placement of the tubular member 6500 within the wellbore casing 6560. In a preferred embodiment, the outside diameter of the intermediate portion 6530 of the tubular body 6505 ranges from about 75% to 98% of the outside diameters of the first and second ends, 6520 and 6535, in order to optimally protect the intermediate sealing member 6550 during placement of the tubular member 6500 within the wellbore casing 6560. The intermediate portion 6530 of the tubular body 6505 includes a wall thickness t_{INT} .

The second end 6535 of the tubular body 6505 is coupled to the intermediate portion 6530 of the tubular body. The second end 6520 of the tubular body 6505 preferably includes the second expandable threaded connection 6540 and the second sealing member 6555. In a preferred embodiment, the outside diameter of the second end 6535 of the tubular body 6505 is greater than the outside diameter of the intermediate portion 6530 of the tubular body 6530. In this manner, the intermediate sealing member 6550 is optimally protected during placement of the tubular member 6500 within a wellbore casing 6560. In a preferred embodiment, the outside diameter of the second end 6535 of the tubular body 6505 is substantially equal to the outside diameter of the first end 6520 of the tubular body 6505. In this manner, the intermediate sealing member 6550 is optimally protected during placement of the tubular member 6500 within the wellbore casing 6560. In a preferred embodiment, the outside diameter of the second end 6535 of the tubular member 6505 is adapted to permit insertion of the tubular member 6500 into the typical range of wellbore casings. The second end 6535 of the tubular member 6505 includes a wall thickness t_2 .

In a preferred embodiment, the wall thicknesses t_1 and t_2 are substantially equal in order to provide substantially equal burst strength for the first and second ends, 6520 and 6535, of the tubular member 6505. In a preferred embodiment, the wall thickness t_1 and t_2 are both greater than the wall thickness t_{INT} in order to optimally match the burst strength of the first and second ends, 6520 and 6535,

of the tubular member 6505 with the intermediate portion 6530 of the tubular member 6505.

The second expandable threaded connection 6540 is coupled to the second end 6535 of the tubular body 6505. The second expandable threaded connection 5 6540 may comprise any number of conventional commercially available threaded connections suitable for radial expansion. In a preferred embodiment, the second expandable threaded connection 6540 is provided in accordance with the teachings of the expandable threaded connections, 4300, 4500, 4700 and 4900, described above with reference to FIGS. 27-30. In a preferred embodiment, the second 10 expandable threaded connection 6540 is adapted to mate with an adjacent first expandable threaded connection provided in an adjacent tubular member 6500. In this manner, a plurality of tubular members 6500 may be coupled end to end.

The first sealing member 6545 is preferably coupled to the outer surface 6515 of the first end 6520 of the tubular body 6505. The first sealing member 6545 15 preferably protects the first end 6520 of the tubular body 6505 during insertion of the tubular member 6500 into the wellbore 6560. The first sealing member 6545 further preferably seals the interface between the first end 6520 of the tubular body 6505 and interior surface of the wellbore 6560 after radial expansion of the first end 6520 of the tubular body 6505. The first sealing member 6545 preferably 20 has a substantially annular cross section. The outside diameter of the first sealing member 6545 is preferably adapted to facilitate placement of the tubular member 6500 within the typical range of wellbore casings 6560. The first sealing member 6545 may be fabricated from any number of conventional commercially available materials such as, for example, polymer coatings or hard coatings. In a preferred 25 embodiment, the first sealing member 6545 is fabricated from commercially available Armacor to optimally protect and seal the first end 6520 of the tubular body 6505.

The intermediate sealing member 6550 is preferably coupled to the outer surface 6515 of the intermediate portion 6530 of the tubular body 6505. The 30 intermediate sealing member 6550 preferably seals the interface between the intermediate portion 6530 of the tubular body 6505 and interior surface of the wellbore 6560 after radial expansion of the intermediate portion 6530 of the

tubular body 6505. The intermediate sealing member 6550 preferably has a substantially annular cross section. The outside diameter of the intermediate sealing member 6550 is preferably selected to be less than the outside diameters of the first and second ends, 6520 and 6535, of the tubular body 6505 in order to
5 optimally protect the intermediate sealing member 6550 during placement of the tubular member 6500 within the typical range of wellbore casings 6560. The intermediate sealing member 6550 may be fabricated from any number of conventional commercially available materials such as, for example, thermoset or thermoplastic polymers. In a preferred embodiment, the intermediate sealing
10 member 6550 is fabricated from thermoset polymers in order to optimally seal the intermediate portion 6530 of the tubular body 6505.

The second sealing member 6555 is preferably coupled to the outer surface 6515 of the second end 6535 of the tubular body 6505. The second sealing member 6555 preferably protects the second end 6535 of the tubular body 6505 during
15 insertion of the tubular member 6500 into the wellbore 6560. The second sealing member 6545 further preferably seals the interface between the second end 6535 of the tubular body 6505 and interior surface of the wellbore 6560 after radial expansion of the second end 6535 of the tubular body 6505. The second sealing member 6555 preferably has a substantially annular cross section. The outside
20 diameter of the second sealing member 6555 is preferably adapted to facilitate placement of the tubular member 6500 within the typical range of wellbore casings 6560. The second sealing member 6555 may be fabricated from any number of conventional commercially available materials such as, for example, polymeric coatings or hard coatings. In a preferred embodiment, the second sealing member
25 6555 is fabricated from commercially available Armacor in order to optimally protect and seal the second end 6535 of the tubular body 6505.

During placement of the tubular member 6500 within the wellbore casing 6560, the first and second sealing members 6545 and 6555, preferably protect the outside surface 6515 of the first and second ends, 6520 and 6535, of the tubular
30 body 6505 from abrasion with the interior surface of the wellbore casing 6560. In a preferred embodiment, after radial expansion of the tubular body 6505, the first, intermediate, and second sealing members, 6545, 6550 and 6555, preferably seal

the interface between the outside surface 6515 of the tubular body 6505 of the tubular member 6500 and the inside surface of the wellbore casing 6560. During placement of the tubular member 6500 within the wellbore casing 6560, the intermediate sealing member 6550 is preferably protected from contact with the interior walls of the wellbore casing 6560 by recessed outer surface profile of the tubular member 6500.

In a preferred embodiment, the tubular body 6505 further includes first and second transition portions, 6565 and 6570, coupled between the first and second ends, 6520 and 6535, and the intermediate portion 6530 of the tubular body 6505.

10 In a preferred embodiment, the first and second transition portions, 6565 and 6570, are inclined at an angle, α , relative to the longitudinal direction ranging from about 0 to 30 degrees in order to optimally facilitate the radial expansion of the tubular member 6500. In a preferred embodiment, the first and second transition portions, 6565 and 6570, provide a smooth transition between the first and second ends, 6520 and 6535, and the intermediate portion 6530, of the tubular member 6505 in order to minimize stress concentrations.

Referring to FIGS. 49, and 50a to 50e, in a preferred embodiment, the tubular member 6500 is formed by a process 6600. In a preferred embodiment, the process 6600 includes the steps of: (1) upsetting both ends of a tubular member in step 6605; (2) expanding both upset ends of the tubular member in step 6610; (3) stress relieving both expanded upset ends of the tubular member in step 6615; (4) forming expandable threaded connections in both expanded upset ends of the tubular member in step 6620; (5) putting a protective coating of material on the outside diameter of the expanded ends of the tubular member in step 6625; and (6) putting a sealing material on the outside diameter of the non-expanded intermediate portion of the tubular member in step 6630.

As illustrated in FIG. 50a, in step 6605, both ends, 6705a and 6705b, of a tubular member 6700 are upset using conventional upsetting methods. The upset ends, 6705a and 6705b, of the tubular member 6700 include wall thicknesses t_1 and t_2 . The intermediate portion 6710 of the tubular member 6700 includes a wall thickness t_{INT} and an interior diameter D_{INT} . In a preferred embodiment, the wall thicknesses t_1 and t_2 are substantially equal in order to provide burst strength that

is substantially equal along the entire length of the tubular member 6700. In a preferred embodiment, the wall thicknesses t_1 and t_2 are both greater than the wall thickness t_{INT} in order to provide burst strength that is substantially equal along the entire length of the tubular member 6700, and also to optimally facilitate the formation of threaded connections in the first and second ends, 6705a and 6705b.

As illustrated in FIG. 50b, in steps 6610 and 6615, both ends, 6705a and 6705b, of the tubular member 6700 are radially expanded using conventional radial expansion methods, and then both ends, 6705a and 6705b, of the tubular member are stress relieved. The radially expanded ends, 6705a and 6705b, of the tubular member 6700 include interior diameters D_1 and D_2 . In a preferred embodiment, the interior diameters D_1 and D_2 are substantially equal in order to provide a burst strength that is substantially equal. In a preferred embodiment, the ratio of the interior diameters D_1 and D_2 to the interior diameter D_{INT} ranges from about 100% to 120% in order to optimally provide a tubular member for subsequent radial expansion.

In a preferred embodiment, the relationship between the wall thicknesses t_1 , t_2 , and t_{INT} of the tubular member 6700; the inside diameters D_1 , D_2 and D_{INT} of the tubular member 6700; the inside diameter $D_{wellbore}$ of the wellbore casing that the tubular member 6700 will be inserted into; and the outside diameter D_{cone} of the expansion cone that will be used to radially expand the tubular member 6700 within the wellbore casing is given by the following expression:

$$D_{wellbore} - 2 * t_1 \geq D_1 \geq \frac{1}{t_1} \left[(t_1 - t_{INT}) * D_{cone} + t_{INT} * D_{INT} \right] \quad (1)$$

where $t_1 = t_2$; and

$$D_1 = D_2.$$

By satisfying the relationship given in equation (1), the expansion forces placed upon the tubular member 6700 during the subsequent radial expansion process are substantially equalized. More generally, the relationship given in equation (1) may be used to calculate the optimal geometry for the tubular member 6700 for subsequent radial expansion of the tubular member 6700 for fabricating and/or repairing a wellbore casing, a pipeline, or a structural support.

As illustrated in FIG. 50c, in step 6620, expandable threads 6715a and 6715b, are formed in both expanded ends, 6705a and 6705b, of the tubular member 6700. The expandable threads, 6715a and 6715b, may be formed in the expanded ends, 6705a and 6705b, of the tubular member 6700 using any number of conventional commercially available methods for forming expandable threads in a tubular member. In a preferred embodiment, the expandable threads, 6715a and 6715b, are provided in accordance with the teachings of the expandable threaded connections, 4300, 4500, 4700 and 4900, described above with reference to FIGS. 27-30, and are formed using conventional processes for forming pin and box type threaded connections available from Atlas-Bradford.

As illustrated in FIG. 50d, in step 6625, protective coatings, 6720a and 6720b, are then applied onto the outside diameters of the expanded ends, 6705a and 6705b, of the tubular member 6700. The protective coatings, 6720a and 6720b, may be applied to the outside diameters of the expanded ends, 6705a and 6705b, of the tubular member 6700 using any number of conventional commercially available methods. In a preferred embodiment, the protective coatings, 6720a and 6720b, are applied to the outside diameters of the expanded ends, 6705a and 6705b, of the tubular member 6700 using commercially available chemical and temperature resistant adhesive bonding.

As illustrated in FIG. 50e, in step 6730, a sealing member 6725 is then applied onto the outside diameter of the non-expanded intermediate portion 6710 of the tubular member 6700. The sealing member 6725 may be applied to the outside diameter of the non-expanded intermediate portion 6710 of the tubular member 6700 using any number of conventional commercially available methods. In a preferred embodiment, the sealing member 6725 is applied to the outside diameter of the intermediate portion 6710 of the tubular member 6700 using commercially available chemical and temperature resistant adhesive bonding.

Referring to FIG. 51, a preferred embodiment of an expansion cone 6700 for radially expanding the tubular member 6500 will now be described. The expansion cone 6700 preferably includes a front end 6705, a rear end 6710, and a radial expansion section 6715. In a preferred embodiment, the expansion cone 6700 is used in one or more the embodiments of apparatus and methods for radially

expanding a tubular member described above with reference to FIGS. 1-47. In a preferred embodiment, when the expansion cone 6700 is displaced in the longitudinal direction relative to the tubular member 6500, the interaction of the exterior surface of the radial expansion section 6715 with the interior surface of the tubular member 6500 causes the tubular member 6500 to expand in the radial direction.

The radial expansion section 6715 preferably includes a first conical outer surface 6720 and a second conical outer surface 6725. The first conical outer surface 6720 includes an angle of attack α_1 , and the second conical outer surface 6725 includes an angle of attack α_2 . In a preferred embodiment, the angle of attack α_1 is greater than the angle of attack α_2 . In this manner, the first conical outer surface 6720 optimally radially overexpands the intermediate portion 6530 of the tubular member 6500 and the second conical outer surface 6725 optimally radially overexpands the pre-expanded first and second ends, 6520 and 6535, of the tubular member 6500. In a preferred embodiment, the first conical outer surface 6720 includes an angle of attack α_1 ranging from about 8 to 20 degrees. In a preferred embodiment, the second conical outer surface 6725 includes an angle of attack α_2 ranging from about 4 to 15 degrees. More generally, the expansion cone 6700 may include 3 or more adjacent conical outer surfaces having angles of attack that decrease from the front end 6705 of the expansion cone 6700 to the rear end 6710 of the expansion cone 6700.

Referring to FIG. 52, an alternative preferred embodiment of an expansion cone 6800 for radially expanding the tubular member 6500 will now be described. The expansion cone 6800 preferably includes a front end 6805, a rear end 6810, and a radial expansion section 6815. In a preferred embodiment, the expansion cone 6800 is used in one or more the embodiments of apparatus and methods for radially expanding a tubular member described above with reference to FIGS. 1-47. In a preferred embodiment, when the expansion cone 6800 is displaced in the longitudinal direction relative to the tubular member 6500, the interaction of the exterior surface of the radial expansion section 6815 with the interior surface of the tubular member 6500 causes the tubular member 6500 to expand in the radial direction.

The radial expansion section 6815 preferably includes an outer surface 6820 having a substantially parabolic outer profile. In this manner, the outer surface 6820 provides an angle of attack that constantly decreases from a maximum at the front end 6805 of the expansion cone 6800 to a minimum at the rear end 6810 of the expansion cone. The parabolic outer profile of the outer surface 6820 may be formed using a plurality of adjacent discrete conical sections and/or using a continuous curved surface. In this manner, the area of the outer surface 6820 adjacent to the front end 6805 of the expansion cone 6800 optimally radially overexpands the intermediate portion 6530 of the tubular member 6500, while the area of the outer surface 6820 adjacent to the rear end 6810 of the expansion cone 6800 optimally radially overexpands the pre-expanded first and second ends, 6520 and 6535, of the tubular member 6500. In a preferred embodiment, the parabolic profile of the outer surface 6820 is selected to provide an angle of attack that ranges from about 8 to 20 degrees in the vicinity of the front end 6805 of the expansion cone 6800 and an angle of attack in the vicinity of the rear end 6810 of the expansion cone 6800 from about 4 to 15 degrees.

Referring now to Figs 53a, 53b and 53c, an embodiment of a system for providing a wellbore casing having a substantially constant interior diameter will now be described. The system preferably provides a two-step process for forming a wellbore casing having a substantially constant interior diameter.

As illustrated in Fig. 53a, in a preferred embodiment, during the first step of the process for forming a wellbore casing having a substantially constant interior diameter, a wellbore casing 6900 is formed within a wellbore 6905 that includes a first tubular member 6910, an annular cement liner 6915, a second tubular member 6920, and one or more annular seals 6925. The upper end 6930 of the second tubular member 6920 and/or the annular seals 6925 are preferably radially expanded into intimate contact with the interior walls of the lower end 6935 of the first tubular member 6910 using one or more of the methods and apparatus described above, with reference to Figs. 1-52, for radially expanding a second tubular member into contact with a first tubular member. In a preferred embodiment, the inside diameter of the second tubular member 6920 is increased by about 2 to 50% during this first stage of the process.

As illustrated in Fig. 53b, in a preferred embodiment, during the second step of the process for forming a wellbore casing having a substantially constant interior diameter, an expansion assembly 6940 is positioned within the first tubular member 6910 above the upper end 6930 of the second tubular member 6920. In a preferred embodiment, the expansion assembly 6940 includes an expansion mandrel 6945, a support member 6950, a slip joint 6955, fluid conduit 6960, a packer 6965, a fluid conduit 6970, and a pump 6975.

The expansion mandrel 6945 is coupled to the support member 6950. The expansion mandrel 6945 is preferably adapted to radially expand the first and second tubular members, 6910 and 6920. In a preferred embodiment, the expansion mandrel 6945 further includes a pair of opposing tapered conical outer surfaces 6980a and 6980b in order to optimally facilitate placement of the expansion mandrel 6945 within the confines of the interior of the first tubular member 6910. In a preferred embodiment, the maximum outside diameter of the expansion mandrel 6945 is substantially equal to the inside diameter of the first tubular member 6910 in order to optimally radially expand the first and second tubular members, 6910 and 6920. In a preferred embodiment, the expansion mandrel 6945 incorporates one or more of the teachings of the present disclosure for optimizing the operational efficiency of an expansion mandrel.

The support member 6950 is preferably coupled to the expansion mandrel 6945, slidingly and sealingly coupled to the packer 6965, and supported by a conventional drilling rig positioned at a surface location. The support member 6950 is preferably adapted to support and position the expansion mandrel 6945 within the wellbore 6905. In a preferred embodiment, the support member 6950 further includes a conventional slip joint 6955 for slidingly coupling the expansion mandrel 6945 to the support member 6950. In a preferred embodiment, the slip joint 6955 permits the expansion mandrel 6945 to be displaced from about 15 to 30 feet in the axial direction relative to the support member 6950. The support member 6950 may comprise any number of conventional commercially available tubular support members modified in accordance with the teachings of the present disclosure.

The fluid conduit 6960 is coupled to and positioned within the expansion mandrel 6945 and the support member 6950. The fluid conduit 6960 is preferably adapted to convey fluidic materials located within the region 6985 below the expansion mandrel 6945 to a region above the packer 6965. In this manner, the axial displacement of the expansion mandrel 6945 is optimally facilitated.

The packer 6965 is sealingly coupled to the first tubular member 6910, sealingly coupled to the fluid conduit 6970, and sealingly and slidingly coupled to the support member 6950. The packer 6965 is preferably adapted to permit the support member 6950 to move in an axial direction, relative to the packer 6965, while also maintaining an operating pressure within an annular region 6990 between the top of the expansion mandrel 6945 and the bottom of the packer 6965 ranging up to about 15,000 psi. In this manner, the pressurization of the annular region 6990 is optimally facilitated. The packer 6965 may comprise any number of conventional commercially available packers modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the packer 6965 is a 10,000 psi blowout preventor stack available from Cameron Iron Works.

The fluid conduit 6970 is fluidically coupled to the output of the pump 6975, sealingly coupled to the packer 6965, and fluidically coupled to the annular region 6990. The fluid conduit 6970 is preferably adapted to convey fluidic materials at operating pressures and flow rates ranging from about 500 to 15,000 psi and 0 to 1000 gallons/minute, respectively from the pump 6975 to the annular region 6990.

The output of the pump 6975 is fluidically coupled to the fluidic conduit 6970 and the input of the pump 6975 is fluidically coupled to a supply of fluidic materials. The pump 6975 is preferably adapted to convey fluidic materials at operating pressures and flow rates ranging from about 500 to 15,000 psi and 0 to 1,000 gallons/minute, respectively. The pump 6975 may comprise any number of conventional commercially available pumps modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the pump 6975 is a HP-400 cement unit pump available from Halliburton.

In a preferred embodiment, during the second step of the process for forming a wellbore casing having a substantially constant interior diameter, the expansion mandrel 6945 is positioned above the upper end 6930 of the second

tubular member 6920. The packer 6965 is then activated and the annular region 6990 is sealed off. The pump 6975 is then activated and fluidic materials are pumped into the fluidic conduit 6970 for injection into the annular region 6990. In a preferred embodiment, the annular region 6990 is pressurized to operating pressures ranging from about 500 to 15,000 psi in order to optimally displace the expansion mandrel 6945 in the axial direction. Pressurization of the annular region 6990 preferably causes the expansion mandrel 6945 to be displaced in the axial direction. In a preferred embodiment, during axial displacement of the expansion mandrel 6945, the support member 6955 is substantially stationary and the expansion mandrel 6945 is displaced relative to the support member 6955 using the slip joint 6955. In an alternative preferred embodiment, the support member 6950 is axially displaced during axial displacement of the expansion mandrel 6945. In another alternative preferred embodiment, the slip joint 6955 is omitted and the support member 6950 is axially displaced during axial displacement of the expansion mandrel 6945.

During axial displacement of the expansion mandrel 6945, fluidic materials located in the region 6985 beneath the expansion mandrel 6945 are preferably conveyed to a region above the packer 6965 using the fluidic conduit 6960. In this manner, the axial displacement of the expansion mandrel 6945 is optimally facilitated. In a preferred embodiment, the axial displacement of the expansion mandrel 6945 is further increased by applying an axial force directly to the support member 6950.

In a preferred embodiment, during axial displacement of the expansion mandrel 6945, the interface between the support member 6950 and packer 6965 is preferably substantially sealed in order to maintain operating pressure within the annular region 6975. In an alternative preferred embodiment, during axial displacement of the expansion mandrel 6945 and support member 6950, the interface between the support member 6950 and packer 6965 is preferably substantially sealed in order to maintain operating pressure within the annular region 6975.

Once the radial expansion process is completed, the expansion mandrel 6945, support member 6950 and packer 6965 are removed from the wellbore 6905.

In an alternative embodiment, the expansion mandrel 6945 is pulled out of the wellbore 6905 with sufficient force to radially expand the first and/or second tubular members, 6910 and 6920. In this manner, any spring back by the first and/or second tubular member, 6910 and 6920, after the initial radial expansion
5 by the expansion mandrel 6945 can be substantially eliminated.

As illustrated in Fig. 53c, the displacement of the expansion mandrel 6945 in the axial direction preferably radially expands both the first and second tubular members, 6910 and 6920, in the radial direction. In a preferred embodiment, after radial expansion of the first and second tubular members, 6910 and 6920, using
10 the expansion assembly 6940, the interior diameters of the radially unexpanded portion of the first tubular member 6910 and the radially expanded portion of the second tubular member 6920 are substantially equal. In this manner, a wellbore casing is provided having a substantially constant interior diameter.

In an exemplary embodiment, the resulting overlapping joint formed by the
15 interface between the radially expanded lower portion 6935 of the first tubular member 6910 and the radially expanded upper portion 6930 of the second tubular member 6920 provides a pressure seal rating that is greater than the pressure seal rating provided by a conventional threaded connection with O-rings provided between the first and second tubular members, 6910 and 6920. As will be
20 recognized by persons having ordinary skill in the art, the pressure seal rating is a measure of the amount of fluid pressure that can be maintained by a sealing joint.

In an exemplary embodiment, the resulting overlapping joint formed by the interface between the radially expanded lower portion 6935 of the first tubular
25 member 6910 and the radially expanded upper portion 6930 of the second tubular member 6920 provides a burst capacity that is greater than the individual burst capacities for the first tubular member 6910 and the second tubular member 6920. As will be recognized by persons having ordinary skill in the art, the burst capacity is the amount of internal pressure that can be contained by a pressure housing.

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In an exemplary embodiment, the resulting overlapping joint formed by the interface between the radially expanded lower portion 6935 of the first tubular

member 6910 and the radially expanded upper portion 6930 of the second tubular member 6920 also has a tensile pullout rating that is greater than the individual tensile yield points for the first and second tubular members 6910 and 6920. As will be recognized by persons having ordinary skill in the art, the tensile pullout
5 rating refers to the amount of tensile force required to pull apart a connection between two tubular members and the tensile yield point refers to the amount of tensile force required to cause a tubular member to yield.

In an exemplary embodiment, the resulting overlapping joint formed by the interface between the radially expanded lower portion 6935 of the first tubular
10 member 6910 and the radially expanded upper portion 6930 of the second tubular member 6920 also provides a torsional failure point that is greater than the individual torsional yield points for the first and second tubular members 6910 and 6920. As will be recognized by persons having ordinary skill in the art, the torsional failure point refers to the amount of torque required to cause a
15 connection between two tubular members to fail and the torsional yield point refers to the amount of torque required to cause a tubular member to yield.

Thus, a method of forming a wellbore casing having a substantially constant interior diameter is provided that preferably includes a two-step radial expansion process. In a preferred embodiment, during the first step of the process, the upper
20 end 6930 of the second tubular member 6920 is expanded into contact with the lower end 6935 of the first tubular member 6910 using one or more of the methods described above with reference to Figs. 1-52. In a preferred embodiment, during the second step of the process, the expansion mandrel 6945 is axially displaced within, and relative to, the first and second tubular members, 6910 and 6920. As
25 a result of the axial displacement of the expansion mandrel 6945, the first and second tubular members, 6910 and 6920, are preferably radially expanded. In a preferred embodiment, the interior diameters of the first and second tubular members, 6910 and 6920, are increased by about 0 to 50% during the second stage of the process. Furthermore, the interior diameters of the radially unexpanded
30 portion of the first tubular member 6910 and the radially expanded portion of the second tubular member 6920 are preferably substantially equal.

In several alternative embodiments, the two-step process illustrated in Figs. 69a to 69c is used to repair and/or form a wellbore casing, a pipeline, or a structural support.

A method of creating a casing in a borehole located in a subterranean formation has been described that includes installing a tubular liner and a mandrel in the borehole. A body of fluidic material is then injected into the borehole. The tubular liner is then radially expanded by extruding the liner off of the mandrel. The injecting preferably includes injecting a hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the tubular liner; and a non hardenable fluidic material into an interior region of the tubular liner below the mandrel. The method preferably includes fluidically isolating the annular region from the interior region before injecting the second quantity of the non hardenable sealing material into the interior region. The injecting the hardenable fluidic sealing material is preferably provided at operating pressures and flow rates ranging from about 0 to 5000 psi and 0 to 1,500 gallons/min. The injecting of the non hardenable fluidic material is preferably provided at operating pressures and flow rates ranging from about 500 to 9000 psi and 40 to 3,000 gallons/min. The injecting of the non hardenable fluidic material is preferably provided at reduced operating pressures and flow rates during an end portion of the extruding. The non hardenable fluidic material is preferably injected below the mandrel. The method preferably includes pressurizing a region of the tubular liner below the mandrel. The region of the tubular liner below the mandrel is preferably pressurized to pressures ranging from about 500 to 9,000 psi. The method preferably includes fluidically isolating an interior region of the tubular liner from an exterior region of the tubular liner. The method further preferably includes curing the hardenable sealing material, and removing at least a portion of the cured sealing material located within the tubular liner. The method further preferably includes overlapping the tubular liner with an existing wellbore casing. The method further preferably includes sealing the overlap between the tubular liner and the existing wellbore casing. The method further preferably includes supporting the extruded tubular liner using the overlap with the existing wellbore casing. The method further preferably includes testing the integrity of the seal in

the overlap between the tubular liner and the existing wellbore casing. The method further preferably includes removing at least a portion of the hardenable fluidic sealing material within the tubular liner before curing. The method further preferably includes lubricating the surface of the mandrel. The method further
5 preferably includes absorbing shock. The method further preferably includes catching the mandrel upon the completion of the extruding.

An apparatus for creating a casing in a borehole located in a subterranean formation has been described that includes a support member, a mandrel, a tubular member, and a shoe. The support member includes a first fluid passage.
10 The mandrel is coupled to the support member and includes a second fluid passage. The tubular member is coupled to the mandrel. The shoe is coupled to the tubular liner and includes a third fluid passage. The first, second and third fluid passages are operably coupled. The support member preferably further includes a pressure relief passage, and a flow control valve coupled to the first fluid passage and the
15 pressure relief passage. The support member further preferably includes a shock absorber. The support member preferably includes one or more sealing members adapted to prevent foreign material from entering an interior region of the tubular member. The mandrel is preferably expandable. The tubular member is preferably fabricated from materials selected from the group consisting of Oilfield
20 Country Tubular Goods, 13 chromium steel tubing/casing, and plastic casing. The tubular member preferably has inner and outer diameters ranging from about 3 to 15.5 inches and 3.5 to 16 inches, respectively. The tubular member preferably has a plastic yield point ranging from about 40,000 to 135,000 psi. The tubular member preferably includes one or more sealing members at an end portion. The
25 tubular member preferably includes one or more pressure relief holes at an end portion. The tubular member preferably includes a catching member at an end portion for slowing down the mandrel. The shoe preferably includes an inlet port coupled to the third fluid passage, the inlet port adapted to receive a plug for blocking the inlet port. The shoe preferably is drillable.

30 A method of joining a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, has been described that includes positioning a

mandrel within an interior region of the second tubular member, positioning the first and second tubular members in an overlapping relationship, pressurizing a portion of the interior region of the second tubular member; and extruding the second tubular member off of the mandrel into engagement with the first tubular member. The pressurizing of the portion of the interior region of the second tubular member is preferably provided at operating pressures ranging from about 500 to 9,000 psi. The pressurizing of the portion of the interior region of the second tubular member is preferably provided at reduced operating pressures during a latter portion of the extruding. The method further preferably includes sealing the overlap between the first and second tubular members. The method further preferably includes supporting the extruded first tubular member using the overlap with the second tubular member. The method further preferably includes lubricating the surface of the mandrel. The method further preferably includes absorbing shock.

15 A liner for use in creating a new section of wellbore casing in a subterranean formation adjacent to an already existing section of wellbore casing has been described that includes an annular member. The annular member includes one or more sealing members at an end portion of the annular member, and one or more pressure relief passages at an end portion of the annular member.

20 A wellbore casing has been described that includes a tubular liner and an annular body of a cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel. The tubular liner is preferably formed by the process of placing the tubular liner and mandrel within the wellbore, and pressurizing an interior portion of the tubular liner. The annular body of the cured fluidic sealing material is preferably formed by the process of injecting a body of hardenable fluidic sealing material into an annular region external of the tubular liner. During the pressurizing, the interior portion of the tubular liner is preferably fluidically isolated from an exterior portion of the tubular liner. The interior portion of the tubular liner is preferably pressurized to pressures ranging from about 500 to 9,000 psi. The tubular liner preferably overlaps with an existing wellbore casing. The wellbore casing preferably further includes a seal positioned in the overlap between the tubular liner and the existing

wellbore casing. Tubular liner is preferably supported the overlap with the existing wellbore casing.

A method of repairing an existing section of a wellbore casing within a borehole has been described that includes installing a tubular liner and a mandrel
5 within the wellbore casing, injecting a body of a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner, and radially expanding the liner in the borehole by extruding the liner off of the mandrel. In a preferred embodiment, the fluidic material is selected from the group consisting of slag mix, cement, drilling mud, and epoxy. In a preferred embodiment, the
10 method further includes fluidically isolating an interior region of the tubular liner from an exterior region of the tubular liner. In a preferred embodiment, the injecting of the body of fluidic material is provided at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min. In a preferred embodiment, the injecting of the body of fluidic material is provided at
15 reduced operating pressures and flow rates during an end portion of the extruding. In a preferred embodiment, the fluidic material is injected below the mandrel. In a preferred embodiment, a region of the tubular liner below the mandrel is pressurized. In a preferred embodiment, the region of the tubular liner below the mandrel is pressurized to pressures ranging from about 500 to 9,000 psi. In a
20 preferred embodiment, the method further includes overlapping the tubular liner with the existing wellbore casing. In a preferred embodiment, the method further includes sealing the interface between the tubular liner and the existing wellbore casing. In a preferred embodiment, the method further includes supporting the extruded tubular liner using the existing wellbore casing. In a preferred
25 embodiment, the method further includes testing the integrity of the seal in the interface between the tubular liner and the existing wellbore casing. In a preferred embodiment, method further includes lubricating the surface of the mandrel. In a preferred embodiment, the method further includes absorbing shock. In a preferred embodiment, the method further includes catching the
30 mandrel upon the completion of the extruding. In a preferred embodiment, the method further includes expanding the mandrel in a radial direction.

A tie-back liner for lining an existing wellbore casing has been described that includes a tubular liner and an annular body of a cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel. The annular body of a cured fluidic sealing material is coupled
5 to the tubular liner. In a preferred embodiment, the tubular liner is formed by the process of placing the tubular liner and mandrel within the wellbore, and pressurizing an interior portion of the tubular liner. In a preferred embodiment, during the pressurizing, the interior portion of the tubular liner is fluidically isolated from an exterior portion of the tubular liner. In a preferred embodiment, the
10 interior portion of the tubular liner is pressurized at pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the annular body of a cured fluidic sealing material is formed by the process of injecting a body of hardenable fluidic sealing material into an annular region between the existing wellbore casing and the tubular liner. In a preferred embodiment, the tubular liner overlaps with
15 another existing wellbore casing. In a preferred embodiment, the tie-back liner further includes a seal positioned in the overlap between the tubular liner and the other existing wellbore casing. In a preferred embodiment, tubular liner is supported by the overlap with the other existing wellbore casing.

An apparatus for expanding a tubular member has been described that
20 includes a support member, a mandrel, a tubular member, and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member. The mandrel includes a second fluid passage operably coupled to the first fluid passage, an interior portion, and an exterior portion. The interior portion of the mandrel is drillable. The tubular member is coupled to the mandrel.
25 The shoe is coupled to the tubular member. The shoe includes a third fluid passage operably coupled to the second fluid passage, an interior portion, and an exterior portion. The interior portion of the shoe is drillable. Preferably, the interior portion of the mandrel includes a tubular member and a load bearing member. Preferably, the load bearing member comprises a drillable body.
30 Preferably, the interior portion of the shoe includes a tubular member, and a load bearing member. Preferably, the load bearing member comprises a drillable body. Preferably, the exterior portion of the mandrel comprises an expansion cone.

Preferably, the expansion cone is fabricated from materials selected from the group consisting of tool steel, titanium, and ceramic. Preferably, the expansion cone has a surface hardness ranging from about 58 to 62 Rockwell C. Preferably at least a portion of the apparatus is drillable.

5 A wellhead has also been described that includes an outer casing and a plurality of substantially concentric and overlapping inner casings coupled to the outer casing. Each inner casing is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer casing. In a preferred embodiment, the outer casing has a yield strength ranging from about 40,000 to
10 135,000 psi. In a preferred embodiment, the outer casing has a burst strength ranging from about 5,000 to 20,000 psi. In a preferred embodiment, the contact pressure between the inner casings and the outer casing ranges from about 500 to 10,000 psi. In a preferred embodiment, one or more of the inner casings include one or more sealing members that contact with an inner surface of the outer
15 casing. In a preferred embodiment, the sealing members are selected from the group consisting of lead, rubber, Teflon, epoxy, and plastic. In a preferred embodiment, a Christmas tree is coupled to the outer casing. In a preferred embodiment, a drilling spool is coupled to the outer casing. In a preferred embodiment, at least one of the inner casings is a production casing.

20 A wellhead has also been described that includes an outer casing at least partially positioned within a wellbore and a plurality of substantially concentric inner casings coupled to the interior surface of the outer casing by the process of expanding one or more of the inner casings into contact with at least a portion of the interior surface of the outer casing. In a preferred embodiment, the inner
25 casings are expanded by extruding the inner casings off of a mandrel. In a preferred embodiment, the inner casings are expanded by the process of placing the inner casing and a mandrel within the wellbore; and pressurizing an interior portion of the inner casing. In a preferred embodiment, during the pressurizing, the interior portion of the inner casing is fluidically isolated from an exterior portion
30 of the inner casing. In a preferred embodiment, the interior portion of the inner casing is pressurized at pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, one or more seals are positioned in the interface between

the inner casings and the outer casing. In a preferred embodiment, the inner casings are supported by their contact with the outer casing.

A method of forming a wellhead has also been described that includes drilling a wellbore. An outer casing is positioned at least partially within an upper
5 portion of the wellbore. A first tubular member is positioned within the outer casing. At least a portion of the first tubular member is expanded into contact with an interior surface of the outer casing. A second tubular member is positioned within the outer casing and the first tubular member. At least a portion of the second tubular member is expanded into contact with an interior portion of
10 the outer casing. In a preferred embodiment, at least a portion of the interior of the first tubular member is pressurized. In a preferred embodiment, at least a portion of the interior of the second tubular member is pressurized. In a preferred embodiment, at least a portion of the interiors of the first and second tubular members are pressurized. In a preferred embodiment, the pressurizing
15 of the portion of the interior region of the first tubular member is provided at operating pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the pressurizing of the portion of the interior region of the second tubular member is provided at operating pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the pressurizing of the portion of the
20 interior region of the first and second tubular members is provided at operating pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the pressurizing of the portion of the interior region of the first tubular member is provided at reduced operating pressures during a latter portion of the expansion. In a preferred embodiment, the pressurizing of the portion of the interior region
25 of the second tubular member is provided at reduced operating pressures during a latter portion of the expansion. In a preferred embodiment, the pressurizing of the portion of the interior region of the first and second tubular members is provided at reduced operating pressures during a latter portion of the expansions. In a preferred embodiment, the contact between the first tubular member and the
30 outer casing is sealed. In a preferred embodiment, the contact between the second tubular member and the outer casing is sealed. In a preferred embodiment, the contact between the first and second tubular members and the outer casing is

sealed. In a preferred embodiment, the expanded first tubular member is supported using the contact with the outer casing. In a preferred embodiment, the expanded second tubular member is supported using the contact with the outer casing. In a preferred embodiment, the expanded first and second tubular members are supported using their contacts with the outer casing. In a preferred embodiment, the first and second tubular members are extruded off of a mandrel. In a preferred embodiment, the surface of the mandrel is lubricated. In a preferred embodiment, shock is absorbed. In a preferred embodiment, the mandrel is expanded in a radial direction. In a preferred embodiment, the first and second tubular members are positioned in an overlapping relationship. In a preferred embodiment, an interior region of the first tubular member is fluidically isolated from an exterior region of the first tubular member. In a preferred embodiment, an interior region of the second tubular member is fluidically isolated from an exterior region of the second tubular member. In a preferred embodiment, the interior region of the first tubular member is fluidically isolated from the region exterior to the first tubular member by injecting one or more plugs into the interior of the first tubular member. In a preferred embodiment, the interior region of the second tubular member is fluidically isolated from the region exterior to the second tubular member by injecting one or more plugs into the interior of the second tubular member. In a preferred embodiment, the pressurizing of the portion of the interior region of the first tubular member is provided by injecting a fluidic material at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/minute. In a preferred embodiment, the pressurizing of the portion of the interior region of the second tubular member is provided by injecting a fluidic material at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/minute. In a preferred embodiment, fluidic material is injected beyond the mandrel. In a preferred embodiment, a region of the tubular members beyond the mandrel is pressurized. In a preferred embodiment, the region of the tubular members beyond the mandrel is pressurized to pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the first tubular member comprises a production casing. In a preferred embodiment, the contact between the first tubular member

and the outer casing is sealed. In a preferred embodiment, the contact between the second tubular member and the outer casing is sealed. In a preferred embodiment, the expanded first tubular member is supported using the outer casing. In a preferred embodiment, the expanded second tubular member is supported using the outer casing. In a preferred embodiment, the integrity of the seal in the contact between the first tubular member and the outer casing is tested.

In a preferred embodiment, the integrity of the seal in the contact between the second tubular member and the outer casing is tested. In a preferred embodiment, the mandrel is caught upon the completion of the extruding. In a preferred embodiment, the mandrel is drilled out. In a preferred embodiment, the mandrel is supported with coiled tubing. In a preferred embodiment, the mandrel is coupled to a drillable shoe.

An apparatus has also been described that includes an outer tubular member, and a plurality of substantially concentric and overlapping inner tubular members coupled to the outer tubular member. Each inner tubular member is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer inner tubular member. In a preferred embodiment, the outer tubular member has a yield strength ranging from about 40,000 to 135,000 psi. In a preferred embodiment, the outer tubular member has a burst strength ranging from about 5,000 to 20,000 psi. In a preferred embodiment, the contact pressure between the inner tubular members and the outer tubular member ranges from about 500 to 10,000 psi. In a preferred embodiment, one or more of the inner tubular members include one or more sealing members that contact with an inner surface of the outer tubular member. In a preferred embodiment, the sealing members are selected from the group consisting of rubber, lead, plastic, and epoxy.

An apparatus has also been described that includes an outer tubular member, and a plurality of substantially concentric inner tubular members coupled to the interior surface of the outer tubular member by the process of expanding one or more of the inner tubular members into contact with at least a portion of the interior surface of the outer tubular member. In a preferred embodiment, the inner tubular members are expanded by extruding the inner tubular members off

of a mandrel. In a preferred embodiment, the inner tubular members are expanded by the process of: placing the inner tubular members and a mandrel within the outer tubular member; and pressurizing an interior portion of the inner casing. In a preferred embodiment, during the pressurizing, the interior portion
5 of the inner tubular member is fluidically isolated from an exterior portion of the inner tubular member. In a preferred embodiment, the interior portion of the inner tubular member is pressurized at pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the apparatus further includes one or more seals positioned in the interface between the inner tubular members and the outer
10 tubular member. In a preferred embodiment, the inner tubular members are supported by their contact with the outer tubular member.

A wellbore casing has also been described that includes a first tubular member, and a second tubular member coupled to the first tubular member in an overlapping relationship. The inner diameter of the first tubular member is
15 substantially equal to the inner diameter of the second tubular member. In a preferred embodiment, the first tubular member includes a first thin wall section, wherein the second tubular member includes a second thin wall section, and wherein the first thin wall section is coupled to the second thin wall section. In a preferred embodiment, first and second thin wall sections are deformed. In a
20 preferred embodiment, the first tubular member includes a first compressible member coupled to the first thin wall section, and wherein the second tubular member includes a second compressible member coupled to the second thin wall section. In a preferred embodiment, the first thin wall section and the first compressible member are coupled to the second thin wall section and the second
25 compressible member. In a preferred embodiment, the first and second thin wall sections and the first and second compressible members are deformed.

A wellbore casing has also been described that includes a tubular member including at least one thin wall section and a thick wall section, and
a compressible annular member coupled to each thin wall section. In a preferred
30 embodiment, the compressible annular member is fabricated from materials selected from the group consisting of rubber, plastic, metal and epoxy. In a preferred embodiment, the wall thickness of the thin wall section ranges from

about 50 to 100 % of the wall thickness of the thick wall section. In a preferred embodiment, the length of the thin wall section ranges from about 120 to 2400 inches. In a preferred embodiment, the compressible annular member is positioned along the thin wall section. In a preferred embodiment, the compressible annular member is positioned along the thin and thick wall sections. In a preferred embodiment, the tubular member is fabricated from materials selected from the group consisting of oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, automotive grade steel, plastics, fiberglass, high strength and/or deformable materials. In a preferred embodiment, the wellbore casing includes a first thin wall at a first end of the casing, and a second thin wall at a second end of the casing.

A method of creating a casing in a borehole located in a subterranean formation has also been described that includes supporting a tubular liner and a mandrel in the borehole using a support member, injecting fluidic material into the borehole, pressurizing an interior region of the mandrel, displacing a portion of the mandrel relative to the support member, and radially expanding the tubular liner. In a preferred embodiment, the injecting includes injecting hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the tubular liner, and injecting non hardenable fluidic material into an interior region of the mandrel. In a preferred embodiment, the method further includes fluidically isolating the annular region from the interior region before injecting the non hardenable fluidic material into the interior region of the mandrel. In a preferred embodiment, the injecting of the hardenable fluidic sealing material is provided at operating pressures and flow rates ranging from about 0 to 5,000 psi and 0 to 1,500 gallons/min. In a preferred embodiment, the injecting of the non hardenable fluidic material is provided at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min. In a preferred embodiment, the injecting of the non hardenable fluidic material is provided at reduced operating pressures and flow rates during an end portion of the radial expansion. In a preferred embodiment, the fluidic material is injected into one or more pressure chambers. In a preferred embodiment, the one or more pressure chambers are pressurized. In a preferred embodiment, the pressure

chambers are pressurized to pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the method further includes fluidically isolating an interior region of the mandrel from an exterior region of the mandrel. In a preferred embodiment, the interior region of the mandrel is isolated from the region exterior

5 to the mandrel by inserting one or more plugs into the injected fluidic material. In a preferred embodiment, the method further includes curing at least a portion of the fluidic material, and removing at least a portion of the cured fluidic material located within the tubular liner. In a preferred embodiment, the method further includes overlapping the tubular liner with an existing wellbore casing. In a

10 preferred embodiment, the method further includes sealing the overlap between the tubular liner and the existing wellbore casing. In a preferred embodiment, the method further includes supporting the extruded tubular liner using the overlap with the existing wellbore casing. In a preferred embodiment, the method further includes testing the integrity of the seal in the overlap between the tubular liner

15 and the existing wellbore casing. In a preferred embodiment, the method further includes removing at least a portion of the hardenable fluidic sealing material within the tubular liner before curing. In a preferred embodiment, the method further includes lubricating the surface of the mandrel. In a preferred embodiment, the method further includes absorbing shock. In a preferred

20 embodiment, the method further includes catching the mandrel upon the completion of the extruding. In a preferred embodiment, the method further includes drilling out the mandrel. In a preferred embodiment, the method further includes supporting the mandrel with coiled tubing. In a preferred embodiment, the mandrel reciprocates. In a preferred embodiment, the mandrel is displaced in

25 a first direction during the pressurization of the interior region of the mandrel, and the mandrel is displaced in a second direction during a de-pressurization of the interior region of the mandrel. In a preferred embodiment, the tubular liner is maintained in a substantially stationary position during the pressurization of the interior region of the mandrel. In a preferred embodiment, the tubular liner is

30 supported by the mandrel during a de-pressurization of the interior region of the mandrel.

A wellbore casing has also been described that includes a first tubular member having a first inside diameter, and a second tubular member having a second inside diameter substantially equal to the first inside diameter coupled to the first tubular member in an overlapping relationship. The first and second

5 tubular members are coupled by the process of deforming a portion of the second tubular member into contact with a portion of the first tubular member. In a preferred embodiment, the second tubular member is deformed by the process of placing the first and second tubular members in an overlapping relationship, radially expanding at least a portion of the first tubular member, and radially

10 expanding the second tubular member. In a preferred embodiment, the second tubular member is radially expanded by the process of supporting the second tubular member and a mandrel within the wellbore using a support member, injecting a fluidic material into the wellbore, pressurizing an interior region of the mandrel, and displacing a portion of the mandrel relative to the support member.

15 In a preferred embodiment, the injecting includes injecting hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the second liner, and injecting non hardenable fluidic material into an interior region of the mandrel. In a preferred embodiment, the wellbore casing further includes fluidically isolating the annular region from the interior region of

20 the mandrel before injecting the non hardenable fluidic material into the interior region of the mandrel. In a preferred embodiment, the injecting of the hardenable fluidic sealing material is provided at operating pressures and flow rates ranging from about 0 to 5,000 psi and 0 to 1,500 gallons/min. In a preferred embodiment, the injecting of the non hardenable fluidic material is provided at operating

25 pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min. In a preferred embodiment, the injecting of the non hardenable fluidic material is provided at reduced operating pressures and flow rates during an end portion of the radial expansion. In a preferred embodiment, the fluidic material is injected into one or more pressure chambers. In a preferred

30 embodiment, one or more pressure chambers are pressurized. In a preferred embodiment, the pressure chambers are pressurized to pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the wellbore casing further

includes fluidically isolating an interior region of the mandrel from an exterior region of the mandrel. In a preferred embodiment, the interior region of the mandrel is isolated from the region exterior to the mandrel by inserting one or more plugs into the injected fluidic material. In a preferred embodiment, the wellbore casing further includes curing at least a portion of the fluidic material, and removing at least a portion of the cured fluidic material located within the second tubular liner. In a preferred embodiment, the wellbore casing further includes sealing the overlap between the first and second tubular liners. In a preferred embodiment, the wellbore casing further includes supporting the second tubular liner using the overlap with the first tubular liner. In a preferred embodiment, the wellbore casing further includes testing the integrity of the seal in the overlap between the first and second tubular liners. In a preferred embodiment, the wellbore casing further includes removing at least a portion of the hardenable fluidic sealing material within the second tubular liner before curing. In a preferred embodiment, the wellbore casing further includes lubricating the surface of the mandrel. In a preferred embodiment, the wellbore casing further includes absorbing shock. In a preferred embodiment, the wellbore casing further includes catching the mandrel upon the completion of the radial expansion. In a preferred embodiment, the wellbore casing further includes drilling out the mandrel. In a preferred embodiment, the wellbore casing further include supporting the mandrel with coiled tubing. In a preferred embodiment, the mandrel reciprocates. In a preferred embodiment, the mandrel is displaced in a first direction during the pressurization of the interior region of the mandrel; and wherein the mandrel is displaced in a second direction during a depressurization of the interior region of the mandrel. In a preferred embodiment, the second tubular liner is maintained in a substantially stationary position during the pressurization of the interior region of the mandrel. In a preferred embodiment, the second tubular liner is supported by the mandrel during a depressurization of the interior region of the mandrel.

30 An apparatus for expanding a tubular member has also been described that includes a support member including a fluid passage, a mandrel movably coupled to the support member including an expansion cone, at least one pressure chamber

defined by and positioned between the support member and mandrel fluidically coupled to the first fluid passage, and one or more releasable supports coupled to the support member adapted to support the tubular member. In a preferred embodiment, the fluid passage includes a throat passage having a reduced inner diameter. In a preferred embodiment, the mandrel includes one or more annular pistons. In a preferred embodiment, the apparatus includes a plurality of pressure chambers. In a preferred embodiment, the pressure chambers are at least partially defined by annular pistons. In a preferred embodiment, the releasable supports are positioned below the mandrel. In a preferred embodiment, the releasable supports are positioned above the mandrel. In a preferred embodiment, the releasable supports comprise hydraulic slips. In a preferred embodiment, the releasable supports comprise mechanical slips. In a preferred embodiment, the releasable supports comprise drag blocks. In a preferred embodiment, the mandrel includes one or more annular pistons, and an expansion cone coupled to the annular pistons. In a preferred embodiment, one or more of the annular pistons include an expansion cone. In a preferred embodiment, the pressure chambers comprise annular pressure chambers.

An apparatus has also been described that includes one or more solid tubular members, each solid tubular member including one or more external seals, one or more slotted tubular members coupled to the solid tubular members, and a shoe coupled to one of the slotted tubular members. In a preferred embodiment, the apparatus further includes one or more intermediate solid tubular members coupled to and interleaved among the slotted tubular members, each intermediate solid tubular member including one or more external seals. In a preferred embodiment, the apparatus further includes one or more valve members. In a preferred embodiment, one or more of the intermediate solid tubular members include one or more valve members.

A method of joining a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, has also been described that includes positioning a mandrel within an interior region of the second tubular member, pressurizing a portion of the interior region of the mandrel, displacing the mandrel relative to the

second tubular member, and extruding at least a portion of the second tubular member off of the mandrel into engagement with the first tubular member. In a preferred embodiment, the pressurizing of the portion of the interior region of the mandrel is provided at operating pressures ranging from about 500 to 9,000 psi.

- 5 In a preferred embodiment, the pressurizing of the portion of the interior region of the mandrel is provided at reduced operating pressures during a latter portion of the extruding. In a preferred embodiment, the method further includes sealing the interface between the first and second tubular members. In a preferred embodiment, the method further includes supporting the extruded second tubular
- 10 member using the interface with the first tubular member. In a preferred embodiment, the method further includes lubricating the surface of the mandrel. In a preferred embodiment, the method further includes absorbing shock. In a preferred embodiment, the method further includes positioning the first and second tubular members in an overlapping relationship. In a preferred
- 15 embodiment, the method further includes fluidically isolating an interior region of the mandrel an exterior region of the mandrel. In a preferred embodiment, the interior region of the mandrel is fluidically isolated from the region exterior to the mandrel by injecting one or more plugs into the interior of the mandrel. In a preferred embodiment, the pressurizing of the portion of the interior region of the
- 20 mandrel is provided by injecting a fluidic material at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/minute. In a preferred embodiment, the method further includes injecting fluidic material beyond the mandrel. In a preferred embodiment, one or more pressure chambers defined by the mandrel are pressurized. In a preferred embodiment, the pressure
- 25 chambers are pressurized to pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the first tubular member comprises an existing section of a wellbore. In a preferred embodiment, the method further includes sealing the interface between the first and second tubular members. In a preferred embodiment, the method further includes supporting the extruded second tubular
- 30 member using the first tubular member. In a preferred embodiment, the method further includes testing the integrity of the seal in the interface between the first tubular member and the second tubular member. In a preferred embodiment, the

method further includes catching the mandrel upon the completion of the extruding. In a preferred embodiment, the method further includes drilling out the mandrel. In a preferred embodiment, the method further include supporting the mandrel with coiled tubing. In a preferred embodiment, the method further
5 includes coupling the mandrel to a drillable shoe. In a preferred embodiment, the mandrel is displaced in the longitudinal direction. In a preferred embodiment, the mandrel is displaced in a first direction during the pressurization and in a second direction during a de-pressurization.

An apparatus has also been described that includes one or more primary
10 solid tubulars, each primary solid tubular including one or more external annular seals, n slotted tubulars coupled to the primary solid tubulars, n-1 intermediate solid tubulars coupled to and interleaved among the slotted tubulars, each intermediate solid tubular including one or more external annular seals, and a shoe coupled to one of the slotted tubulars.

15 A method of isolating a first subterranean zone from a second subterranean zone in a wellbore has also been described that includes positioning one or more primary solid tubulars within the wellbore, the primary solid tubulars traversing the first subterranean zone, positioning one or more slotted tubulars within the wellbore, the slotted tubulars traversing the second subterranean zone, fluidicly
20 coupling the slotted tubulars and the solid tubulars, and preventing the passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid and slotted tubulars.

A method of extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, has also been
25 described that includes positioning one or more primary solid tubulars within the wellbore, fluidicly coupling the primary solid tubulars with the casing, positioning one or more slotted tubulars within the wellbore, the slotted tubulars traversing the producing subterranean zone, fluidicly coupling the slotted tubulars with the solid tubulars, fluidicly isolating the producing subterranean zone from at least
30 one other subterranean zone within the wellbore, and fluidicly coupling at least one of the slotted tubulars from the producing subterranean zone. In a preferred

embodiment, the method further includes controllably fluidically decoupling at least one of the slotted tubulars from at least one other of the slotted tubulars.

A method of creating a casing in a borehole while also drilling the borehole also has been described that includes installing a tubular liner, a mandrel, and a drilling assembly in the borehole. A fluidic material is injected within the tubular liner, mandrel and drilling assembly. At least a portion of the tubular liner is radially expanded while the borehole is drilled using the drilling assembly. In a preferred embodiment, the injecting includes injecting the fluidic material within an expandable chamber. In a preferred embodiment, the injecting includes injecting hardenable fluidic sealing material into an annular region located between the borehole and the exterior of the tubular liner. In a preferred embodiment, the injecting of the hardenable fluidic sealing material is provided at operating pressures and flow rates ranging from about 0 to 5,000 psi and 0 to 1,500 gallons/min. In a preferred embodiment, the injecting of the fluidic material is provided at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/min. In a preferred embodiment, the injecting of the fluidic material is provided at reduced operating pressures and flow rates during an end portion of the radial expansion. In a preferred embodiment, the method further includes curing at least a portion of the fluidic material; and removing at least a portion of the cured fluidic material located within the tubular liner. In a preferred embodiment, the method further includes overlapping the tubular liner with an existing wellbore casing. In a preferred embodiment, the method further includes sealing the overlap between the tubular liner and the existing wellbore casing. In a preferred embodiment, the method further includes supporting the extruded tubular liner using the overlap with the existing wellbore casing. In a preferred embodiment, the method further includes testing the integrity of the seal in the overlap between the tubular liner and the existing wellbore casing. In a preferred embodiment, the method further includes lubricating the surface of the mandrel. In a preferred embodiment, the method further includes absorbing shock. In a preferred embodiment, the method further includes catching the mandrel upon the completion of the extruding. In a preferred embodiment, the method further includes expanding the mandrel in a radial direction. In a

preferred embodiment, the method further includes drilling out the mandrel. In a preferred embodiment, the method further includes supporting the mandrel with coiled tubing. In a preferred embodiment, the wall thickness of the tubular member is variable. In a preferred embodiment, the mandrel is coupled to a
5 drillable shoe.

An apparatus has also been described that includes a support member, the support member including a first fluid passage; a mandrel coupled to the support member, the mandrel including a second fluid passage; a tubular member coupled to the mandrel; and a shoe coupled to the tubular liner, the shoe including a third
10 fluid passage; and a drilling assembly coupled to the shoe; wherein the first, second and third fluid passages and the drilling assembly are operably coupled. In a preferred embodiment, the support member further includes a pressure relief passage; and a flow control valve coupled to the first fluid passage and the pressure relief passage. In a preferred embodiment, the support member further includes
15 a shock absorber. In a preferred embodiment, the support member includes one or more sealing members adapted to prevent foreign material from entering an interior region of the tubular member. In a preferred embodiment, the support member includes one or more stabilizers. In a preferred embodiment, the mandrel is expandable. In a preferred embodiment, the tubular member is fabricated from
20 materials selected from the group consisting of Oilfield Country Tubular Goods, automotive grade steel, plastic and chromium steel. In a preferred embodiment, the tubular member has inner and outer diameters ranging from about 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the tubular member has a plastic yield point ranging from about 40,000 to 135,000 psi. In a
25 preferred embodiment, the tubular member includes one or more sealing members at an end portion. In a preferred embodiment, the tubular member includes one or more pressure relief holes at an end portion. In a preferred embodiment, the tubular member includes a catching member at an end portion for slowing down movement of the mandrel. In a preferred embodiment, the support member
30 comprises coiled tubing. In a preferred embodiment, at least a portion of the mandrel and shoe are drillable. In a preferred embodiment, the wall thickness of the tubular member in an area adjacent to the mandrel is less than the wall

thickness of the tubular member in an area that is not adjacent to the mandrel. In a preferred embodiment, the apparatus further includes an expandable chamber. In a preferred embodiment, the expandable chamber is approximately cylindrical. In a preferred embodiment, the expandable chamber is approximately
5 annular.

A method of forming an underground pipeline within an underground tunnel including at least a first tubular member and a second tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, has also been described that includes positioning the
10 first tubular member within the tunnel; positioning the second tubular member within the tunnel in an overlapping relationship with the first tubular member; positioning a mandrel and a drilling assembly within an interior region of the second tubular member; injecting a fluidic material within the mandrel, drilling
assembly and the second tubular member; extruding at least a portion of the
15 second tubular member off of the mandrel into engagement with the first tubular member; and drilling the tunnel. In a preferred embodiment, the injecting of the fluidic material is provided at operating pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the injecting of the fluidic material is provided at
reduced operating pressures during a latter portion of the extruding. In a
20 preferred embodiment, the method further includes sealing the interface between the first and second tubular members. In a preferred embodiment, the method further includes supporting the extruded second tubular member using the interface with the first tubular member. In a preferred embodiment, the method
further includes lubricating the surface of the mandrel. In a preferred
25 embodiment, the method further includes absorbing shock. In a preferred embodiment, the method further includes expanding the mandrel in a radial direction. In a preferred embodiment, the method further includes sealing the interface between the first and second tubular members. In a preferred
embodiment, the method further includes supporting the extruded second tubular
30 member using the first tubular member. In a preferred embodiment, the method further includes testing the integrity of the seal in the interface between the first tubular member and the second tubular member. In a preferred embodiment, the

method further includes catching the mandrel upon the completion of the extruding. In a preferred embodiment, the method further includes drilling out the mandrel. In a preferred embodiment, the method further includes supporting the mandrel with coiled tubing. In a preferred embodiment, the method further includes coupling the mandrel to a drillable shoe. In a preferred embodiment, the fluidic material is injected into an expandable chamber. In a preferred embodiment, the expandable chamber is substantially cylindrical. In a preferred embodiment, the expandable chamber is substantially annular. An apparatus has also been described that includes a wellbore, the wellbore formed by the process of drilling the wellbore; and a tubular liner positioned within the wellbore, the tubular liner formed by the process of extruding the tubular liner off of a mandrel while drilling the wellbore. In a preferred embodiment, the tubular liner is formed by the process of: placing the tubular liner and mandrel within the wellbore; and pressurizing an interior portion of the tubular liner. In a preferred embodiment, the interior portion of the tubular liner is pressurized at pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the tubular liner is formed by the process of: placing the tubular liner and mandrel within the wellbore; and pressurizing an interior portion of the mandrel. In a preferred embodiment, the interior portion of the mandrel is pressurized at pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the apparatus further includes an annular body of a cured fluidic material coupled to the tubular liner. In a preferred embodiment, the annular body of a cured fluidic sealing material is formed by the process of: injecting a body of hardenable fluidic sealing material into an annular region external of the tubular liner. In a preferred embodiment, the tubular liner overlaps with an existing wellbore casing. In a preferred embodiment, the apparatus further includes a seal positioned in the overlap between the tubular liner and the existing wellbore casing. In a preferred embodiment, the tubular liner is supported by the overlap with the existing wellbore casing. In a preferred embodiment, the process of extruding the tubular liner includes the pressurizing of an expandable chamber. In a preferred embodiment, the expandable chamber is substantially cylindrical. In a preferred embodiment, the expandable chamber is substantially annular.

A method of forming a wellbore casing in a wellbore has also been described that includes drilling out the wellbore while forming the wellbore casing. In a preferred embodiment, the forming includes: expanding a tubular member in the radial direction. In a preferred embodiment, the expanding includes: displacing
5 a mandrel relative to the tubular member. In a preferred embodiment, the displacing includes: expanding an expandable chamber. In a preferred embodiment, the expandable chamber comprises a cylindrical chamber. In a preferred embodiment, the expandable chamber comprises an annular chamber.

A method of expanding a tubular member has also been described that
10 includes placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the method further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the
15 annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the method further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the method further includes conveying fluids in opposite directions.
20 In a preferred embodiment, the method further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

25 A method of coupling a tubular member to preexisting structure has also been described that includes positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred
30 embodiment, the method further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred

embodiment, the volume of the annular region increases. In a preferred embodiment, the method further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the
5 method further includes conveying fluids in opposite directions. In a preferred embodiment, the method further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from
10 about 0 to 3,000 gallons/minute.

A method of repairing a defect in a preexisting structure using a tubular member has also been described that includes positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the
15 tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the method further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred
20 embodiment, the method further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the method further includes conveying fluids in opposite directions. In a preferred embodiment, the method further includes conveying a pressurized fluid and a non-
25 pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the method further includes sealing the interface between the preexisting structure and the tubular
30 member at ends of the tubular member.

An apparatus for radially expanding a tubular member has also been described that includes a first tubular member, a second tubular member

positioned within the first tubular member, a third tubular member movably coupled to and positioned within the second tubular member, a first annular sealing member for sealing an interface between the first and second tubular members, a second annular sealing member for sealing an interface between the second and third tubular members, and a mandrel positioned within the first tubular member and coupled to an end of the third tubular member. In a preferred embodiment, the apparatus further includes an annular chamber defined by the first tubular member, the second tubular member, the third tubular member, the first annular sealing member, the second annular sealing member, and the mandrel. In a preferred embodiment, the apparatus further includes an annular passage defined by the second tubular member and the third tubular member. In a preferred embodiment, the apparatus further includes a fluid passage contained within the third tubular member and the mandrel. In a preferred embodiment, the apparatus further includes one or more sealing members coupled to an exterior surface of the first tubular member. In a preferred embodiment, the apparatus further includes an annular chamber defined by the first tubular member, the second tubular member, the third tubular member, the first annular sealing member, the second annular sealing member, and the mandrel, and annular passage defined by the second tubular member and the third tubular member. In a preferred embodiment, the annular chamber and the annular passage are fluidically coupled. In a preferred embodiment, the apparatus further includes one or more slips coupled to the exterior surface of the first tubular member. In a preferred embodiment, the mandrel includes a conical surface. In a preferred embodiment, the angle of attack of the conical surface ranges from about 10 to 30 degrees. In a preferred embodiment, the conical surface has a surface hardness ranging from about 58 to 62 Rockwell C.

An apparatus has also been described that includes a tubular member, a piston adapted to expand the diameter of the tubular member positioned within the tubular member, the piston including a passage for conveying fluids out of the tubular member, and an annular chamber defined by the piston and tubular member. In a preferred embodiment, the piston includes a conical surface. In a preferred embodiment, the angle of attack of the conical surface ranges from about

10 to 30 degrees. In a preferred embodiment, the conical surface has a surface hardness ranging from about 58 to 62 Rockwell C. In a preferred embodiment, the tubular member includes one or more sealing members coupled to the exterior surface of the tubular member.

5 A wellbore casing has also been described that includes a first tubular member and a second tubular member coupled to the first tubular member. The second tubular member is coupled to the first tubular member by the process of positioning the second tubular member in an overlapping relationship to the first tubular member, placing a mandrel within the second tubular member,
10 pressurizing an annular region within the second tubular member, and displacing the mandrel with respect to the second tubular member. In a preferred embodiment, the wellbore casing further includes removing fluids within the second tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a
15 preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the wellbore casing further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the wellbore casing further including conveying fluids in opposite
20 directions. In a preferred embodiment, the wellbore casing further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

25 An apparatus has also been described that includes a preexisting structure and a tubular member coupled to the preexisting structure. The tubular member is coupled to the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the
30 tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the apparatus further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a

preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the apparatus further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the apparatus further includes conveying fluids in opposite directions. In a preferred embodiment, the apparatus further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi.

10 In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

An apparatus has also been described that includes a preexisting structure having a defective portion and a tubular member coupled to the defective portion of the preexisting structure. The tubular member is coupled to the defective portion of the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an annular region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the apparatus further includes removing fluids within the tubular member that are displaced by the displacement of the mandrel. In a preferred embodiment, the removed fluids pass inside the annular region. In a preferred embodiment, the volume of the annular region increases. In a preferred embodiment, the apparatus further includes sealing off the annular region. In a preferred embodiment, sealing off the annular region includes sealing a stationary member and sealing a non-stationary member. In a preferred embodiment, the apparatus further includes conveying fluids in opposite directions. In a preferred embodiment, the apparatus further includes conveying a pressurized fluid and a non-pressurized fluid in opposite directions. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred

embodiment, the apparatus further includes sealing the interface between the preexisting structure and the tubular member at ends of the tubular member.

A method of expanding a tubular member has also been described that includes placing a mandrel within the tubular member, pressurizing a region
5 within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the tubular member is expanded
10 beginning at an upper portion of the tubular member.

A method of coupling a tubular member to preexisting structure has also been described that includes positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and
15 displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the tubular member is expanded beginning at an upper portion of the
20 tubular member.

A method of repairing a defect in a preexisting structure using a tubular member has also been described that includes positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the
25 tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the tubular member is expanded beginning at an upper
30 portion of the tubular member. In a preferred embodiment, the method further includes sealing the interface between the preexisting structure and the tubular member at both ends of the tubular member.

An apparatus for radially expanding a tubular member has also been described that includes a first tubular member, a second tubular member coupled to the first tubular member, a third tubular member coupled to the second tubular member, and a mandrel positioned within the second tubular member and coupled
5 to an end portion of the third tubular member. In a preferred embodiment, the mandrel includes a fluid passage having an inlet adapted to receive fluid stop member. In a preferred embodiment, the apparatus further includes one or more slips coupled to the exterior surface of the third tubular member. In a preferred embodiment, the mandrel includes a conical surface. In a preferred embodiment,
10 the angle of attack of the conical surface ranges from about 10 to 30 degrees. In a preferred embodiment, the conical surface has a surface hardness ranging from about 58 to 62 Rockwell C. In a preferred embodiment, the average inside diameter of the second tubular member is greater than the average inside diameter of the third tubular member.

15 An apparatus has also been described that includes a tubular member, a piston adapted to expand the diameter of the tubular member positioned within the tubular member, the piston including a passage for conveying fluids out of the tubular member. In a preferred embodiment, the piston includes a conical surface. In a preferred embodiment, the angle of attack of the conical surface ranges from
20 about 10 to 30 degrees. In a preferred embodiment, the conical surface has a surface hardness ranging from about 58 to 62 Rockwell C. In a preferred embodiment, the tubular member includes one or more sealing members coupled to the exterior surface of the tubular member.

A wellbore casing has also been described that includes a first tubular
25 member and a second tubular member coupled to the first tubular member. The second tubular member is coupled to the first tubular member by the process of: positioning the second tubular member in an overlapping relationship to the first tubular member, placing a mandrel within the second tubular member, pressurizing an interior region within the second tubular member, and displacing
30 the mandrel with respect to the second tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures ranging from

about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

An apparatus has also been described that includes a preexisting structure and a tubular member coupled to the preexisting structure. The tubular member
5 is coupled to the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating pressures
10 ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute.

An apparatus has also been described that includes a preexisting structure having a defective portion and a tubular member coupled to the defective portion of the preexisting structure. The tubular member is coupled to the defective
15 portion of the preexisting structure by the process of: positioning the tubular member in an overlapping relationship to the defect in the preexisting structure, placing a mandrel within the tubular member, pressurizing an interior region within the tubular member, and displacing the mandrel with respect to the tubular member. In a preferred embodiment, the pressurizing is provided at operating
20 pressures ranging from about 0 to 9,000 psi. In a preferred embodiment, the pressurizing is provided at flow rates ranging from about 0 to 3,000 gallons/minute. In a preferred embodiment, the apparatus further includes sealing the interface between the preexisting structure and the tubular member at both ends of the tubular member.

25 An apparatus also has been described that includes a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more sealing members for sealing the interface between the first and second tubular members. In a preferred embodiment, the threaded connection comprises
30 a pin and box threaded connection. In a preferred embodiment, the sealing members are positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, one of the sealing members is positioned adjacent to an

end portion of the threaded connection; and wherein another one of the sealing members is not positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, a plurality of the sealing members are positioned adjacent to an end portion of the threaded connection.

5 An apparatus also has been described that includes a tubular assembly having a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more sealing members for sealing the interface between the first and second tubular members. The tubular assembly is
10 formed by the process of radially expanding the tubular assembly. In a preferred embodiment, the threaded connection comprises a pin and box threaded connection. In a preferred embodiment, the sealing members are positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, one of the sealing members is positioned adjacent to an end portion of the threaded
15 connection; and wherein another one of the sealing members is not positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, a plurality of the sealing members are positioned adjacent to an end portion of the threaded connection.

 An apparatus also has been described that includes a tubular member and
20 a mandrel positioned within the tubular member including a conical surface have an angle of attack ranging from about 10 to 30 degrees. In a preferred embodiment, the tubular member includes a first tubular member, a second tubular member, and a threaded connection for coupling the first tubular member to the second tubular member. The threaded connection includes one or more
25 sealing members for sealing the interface between the first and second tubular members. In a preferred embodiment, the threaded connection comprises a pin and box threaded connection. In a preferred embodiment, the sealing members are positioned adjacent to an end portion of the threaded connection. In a preferred embodiment, one of the sealing members is positioned adjacent to an end portion
30 of the threaded connection; and wherein another one of the sealing members is not positioned adjacent to an end portion of the threaded connection. In a preferred

embodiment, a plurality of the sealing members are positioned adjacent to an end portion of the threaded connection.

An expansion cone for expanding a tubular member has also been described that includes a housing including a tapered first end and a second end, one or more
5 grooves formed in the outer surface of the tapered first end, and one or more axial flow passages fluidically coupled to the circumferential grooves. In a preferred embodiment, the grooves comprise circumferential grooves. In a preferred embodiment, the grooves comprise spiral grooves. In a preferred embodiment, the grooves are concentrated around the axial midpoint of the tapered portion of the
10 housing. In a preferred embodiment, the axial flow passages comprise axial grooves. In a preferred embodiment, the axial grooves are spaced apart by at least about 3 inches in the circumferential direction. In a preferred embodiment, the axial grooves extend from the tapered first end of the body to the grooves. In a preferred embodiment, the axial grooves extend from the second end of the body
15 to the grooves. In a preferred embodiment, the axial grooves extend from the tapered first end of the body to the second end of the body. In a preferred embodiment, the flow passages are positioned within the housing of the expansion cone. In a preferred embodiment, the flow passages extend from the tapered first end of the body to the grooves. In a preferred embodiment, the flow passages
20 extend from the tapered first end of the body to the second end of the body. In a preferred embodiment, the flow passages extend from the second end of the body to the grooves. In a preferred embodiment, one or more of the flow passages include inserts having restricted flow passages. In a preferred embodiment, one or more of the flow passages include filters. In a preferred embodiment, the cross
25 sectional area of the grooves is greater than the cross sectional area of the axial flow passages. In a preferred embodiment, the cross-sectional area of the grooves ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$. In a preferred embodiment, the cross-sectional area of the axial flow passages ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$. In a preferred embodiment, the angle of attack of the first tapered end of the body
30 ranges from about 10 to 30 degrees. In a preferred embodiment, the grooves are concentrated in a trailing edge portion of the tapered first end. In a preferred embodiment, the angle of inclination of the axial flow passages relative to the

longitudinal axis of the expansion cone is greater than the angle of attack of the first tapered end. In a preferred embodiment, the grooves include a flow channel having a first radius of curvature, a first shoulder positioned on one side of the flow channel having a second radius of curvature, and a second shoulder positioned
5 on the other side of the flow channel having a third radius of curvature. In a preferred embodiment, the first, second and third radii of curvature are substantially equal. In a preferred embodiment, the axial flow passages include a flow channel having a first radius of curvature, a first shoulder positioned on one side of the flow channel having a second radius of curvature, and a second shoulder
10 positioned on the other side of the flow channel having a third radius of curvature. In a preferred embodiment, the first, second and third radii of curvature are substantially equal. In a preferred embodiment, the second radius of curvature is greater than the third radius of curvature.

A method of lubricating the interface between a tubular member and an
15 expansion cone having a first tapered end and a second end during the radial expansion of the tubular member by the expansion cone, wherein the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge portion, has also been described that includes injecting a lubricating fluid into the trailing edge portion. In a
20 preferred embodiment, the lubricating fluid has a viscosity ranging from about 1 to 10,000 centipoise. In a preferred embodiment, the injecting includes injecting lubricating fluid into the first tapered end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the area around the axial midpoint of the first tapered end of the expansion cone. In a preferred
25 embodiment, the injecting includes injecting lubricating fluid into the second end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the tapered first end and the second end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the interior of the expansion cone. In a preferred embodiment, the injecting
30 includes injecting lubricating fluid through the outer surface of the expansion cone. In a preferred embodiment, the injecting includes injecting the lubricating fluid into a plurality of discrete locations along the trailing edge portion. In a

preferred embodiment, the lubricating fluid comprises drilling mud. In a preferred embodiment, the lubricating fluid further includes TorqTrim III, EP Mudlib, and DrillN-Slid. In a preferred embodiment, the lubricating fluid comprises TorqTrim III, EP Mudlib, and DrillN-Slid.

5 A method of removing debris formed during the radial expansion of a tubular member by an expansion cone from the interface between the tubular member and the expansion cone, the expansion cone including a first tapered end and a second end, the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge
10 portion, also has been described that includes injecting a lubricating fluid into the interface between the tubular member and the expansion cone. In a preferred embodiment, the lubricating fluid has a viscosity ranging from about 1 to 10,000 centipoise. In a preferred embodiment, the injecting includes injecting lubricating fluid into the first tapered end of the expansion cone. In a preferred embodiment,
15 the injecting includes injecting lubricating fluid into the area around the axial midpoint of the first tapered end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the second end of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the tapered first end and the second end of the expansion
20 cone. In a preferred embodiment, the injecting includes injecting lubricating fluid into the interior of the expansion cone. In a preferred embodiment, the injecting includes injecting lubricating fluid through the outer surface of the expansion cone. In a preferred embodiment, the lubricating fluid comprises drilling mud. In a preferred embodiment, the lubricating fluid further includes TorqTrim III, EP
25 Mudlib, and DrillN-Slid. In a preferred embodiment, the lubricating fluid comprises TorqTrim III, EP Mudlib, and DrillN-Slid.

A tubular member has also been described that includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall
30 thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

A wellbore casing has also been described that includes one or more tubular members. Each tubular member includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

A method of forming a wellbore casing also has been described that includes placing a tubular member and an expansion cone in a wellbore, and displacing the expansion cone relative to the tubular member. The tubular member includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

A method of selecting a group of tubular members for subsequent radial expansion also has been described that includes radially expanding the ends of a representative sample of the group of tubular members, measuring the amount of necking of the walls of the radially expanded ends of the tubular members, and if the radially expanded ends of the tubular members do not exhibit necking for radial expansions of up to about 25%, then accepting the group of tubular members.

A method of selecting a group of tubular members also has been described that includes radially expanding the ends of a representative sample of the group of tubular members until each of the tubular members fail, if the radially expanded ends of the tubular members do not fail for radial expansions of up to about 30%, then accepting the group of tubular members.

A method of inserting a tubular member into a wellbore also has been described that includes injecting a lubricating fluid into the wellbore, and inserting the tubular member into the wellbore. In a preferred embodiment, the lubricating fluid comprises BARO-LUB GOLD-SEAL™ brand drilling mud lubricant.

An expandable tubular member also has been described that includes a first tubular section having a first outer diameter, an intermediate tubular section coupled to the first tubular section having an intermediate outer diameter and a second tubular section having a second outer diameter coupled to the intermediate tubular section having a second outer diameter. The first and second outer diameters are greater than the intermediate outer diameter. In a preferred embodiment, the first tubular section includes a first threaded connection; and wherein the second tubular section includes a second threaded connection. In a preferred embodiment, the first and second threaded connections include pin and box threads. In a preferred embodiment, one of the first and second threaded connections include a sealing member. In a preferred embodiment, an outer surface of the first tubular section includes a first protective member and an outer surface of the second tubular section includes a second protective member. In a preferred embodiment, the first protective member comprises a thermoset polymer and the second protective member comprises a thermoset polymer. In a preferred embodiment, an outer surface of the intermediate tubular section includes a sealing member. In a preferred embodiment, the sealing member comprises a thermoset polymer. In a preferred embodiment, the expandable tubular section further includes a first transitional tubular section coupled between the first tubular section and the intermediate tubular section having a first angle of inclination and a second transitional tubular section coupled between the second tubular section and the intermediate tubular section having a second angle of inclination. The first and second angles of inclination preferably range from about 0 to 30 degrees. In a preferred embodiment, the wall thickness of the first tubular section is substantially equal to the wall thickness of the second tubular section. In a preferred embodiment, the wall thickness of the intermediate tubular section is less than the wall thicknesses of the first and second tubular sections. In a preferred embodiment, the wall thickness of the intermediate tubular section is less than the wall thicknesses of the first and second tubular sections.

30 A method of fabricating an expandable tubular member also has been described that includes providing a tubular member having a first end, a second end, and an intermediate portion and radially expanding the first end and the

second end of the tubular member. In a preferred embodiment, prior to radially expanding, the first end and the second end of the tubular member are upset. In a preferred embodiment, the method further includes forming threaded connections on the first and second radially expanded ends of the tubular member.

- 5 In a preferred embodiment, the method further includes relieving stress in the first and second radially expanded ends of the tubular member. In a preferred embodiment, the method further includes applying a first protective member to the outside diameter of the first end of the tubular member and applying a second protective member to the outside diameter of the second end of the tubular member.
- 10 In a preferred embodiment, the method further includes applying a sealing member to the outside diameter of the intermediate portion of the tubular member. In a preferred embodiment, the relationship between the wall thicknesses of the expandable tubular member; the inside diameters of the expandable tubular member; the inside diameter D_{wellbore} of the wellbore casing that
- 15 the expandable tubular member will be inserted into; and the outside diameter D_{cone} of the expansion cone that will be used to radially expand the expandable tubular member within the wellbore casing is given by the following expression:

$$D_{\text{wellbore}} - 2 * t_1 \geq D_1 \geq \frac{1}{t_1} \left[(t_1 - t_{\text{INT}}) * D_{\text{cone}} + t_{\text{INT}} * D_{\text{INT}} \right]$$

- 20 where D_{wellbore} = inside diameter of the wellbore casing that the expandable tubular member will be inserted into;
- t_1 = wall thickness of the first tubular section;
- t_2 = wall thickness of the second tubular section;
- $t_1 = t_2$;
- t_{INT} = wall thickness of the intermediate tubular section;
- 25 D_1 = inside diameter of the first tubular section;
- D_2 = inside diameter of the second tubular section;
- $D_1 = D_2$;
- D_{INT} = interior diameter of the intermediate tubular section; and

D_{cone} = outside diameter of the expansion cone that will be used to radially expand the expandable tubular member within the wellbore casing.

An expansion cone for radially expanding a tubular member also has been
5 described that includes a first outer surface having a first angle of attack and a second outer surface coupled to the first outer surface having a second angle of attack. The first angle of attack is greater than the second angle of attack. In a preferred embodiment, the expansion cone further includes a front end coupled to the first outer surface and a rear end coupled to the second outer surface. In a
10 preferred embodiment, the first angle of attack ranges from about 8 to 20 degrees; and wherein the second angle of attack ranges from about 4 to 15 degrees. In a preferred embodiment, the expansion cone further includes one or more intermediate outer surfaces coupled between the first and second outer surfaces. In a preferred embodiment, the angle of attack of the intermediate outer surfaces
15 continually decrease from the first outer surface to the second outer surface. In a preferred embodiment, the angle of attack of the intermediate outer surfaces decrease in steps from the first outer surface to the second outer surface. In a preferred embodiment, the angle of attack of the outer surfaces is defined by a parabolic equation. In a preferred embodiment, the angle of attack of the outer
20 surfaces is defined by a parabolic equation.

An apparatus also has been described that includes a tubular member formed by the process of radially expanding an unexpanded tubular member into contact with an approximately cylindrical passage using an expansion cone. The unexpanded tubular member includes a first tubular section having a first outer
25 diameter, an intermediate tubular section coupled to the first tubular section having an intermediate outer diameter and a second tubular section having a second outer diameter coupled to the intermediate tubular section having a second outer diameter. The first and second outer diameters are greater than the intermediate outer diameter. In a preferred embodiment, the first tubular section
30 includes a first threaded connection; and wherein the second tubular section includes a second threaded connection. In a preferred embodiment, the first and second threaded connections include pin and box threads. In a preferred

embodiment, one of the first and second threaded connections include a sealing member. In a preferred embodiment, an outer surface of the first tubular section includes a first protective member and an outer surface of the second tubular section includes a second protective member. In a preferred embodiment, the first
5 protective member comprises a thermoset polymer and the second protective member comprises a thermoset polymer. In a preferred embodiment, an outer surface of the intermediate tubular section includes a sealing member. In a preferred embodiment, the sealing member comprises a thermoset polymer. In a preferred embodiment, the expandable tubular section further includes a first
10 transitional tubular section coupled between the first tubular section and the intermediate tubular section having a first angle of inclination and a second transitional tubular section coupled between the second tubular section and the intermediate tubular section having a second angle of inclination. The first and second angles of inclination preferably range from about 0 to 30 degrees. In a
15 preferred embodiment, the wall thickness of the first tubular section is substantially equal to the wall thickness of the second tubular section. In a preferred embodiment, the wall thickness of the intermediate tubular section is less than the wall thicknesses of the first and second tubular sections. In a preferred embodiment, the wall thickness of the intermediate tubular section is
20 less than the wall thicknesses of the first and second tubular sections. In a preferred embodiment, the expansion cone includes a first outer surface having a first angle of attack and a second outer surface coupled to the first outer surface having a second angle of attack. The first angle of attack is greater than the second angle of attack. In a preferred embodiment, the expansion cone further
25 includes a front end coupled to the first outer surface and a rear end coupled to the second outer surface. In a preferred embodiment, the first angle of attack ranges from about 8 to 20 degrees; and wherein the second angle of attack ranges from about 4 to 15 degrees. In a preferred embodiment, the expansion cone further includes one or more intermediate outer surfaces coupled between the first and
30 second outer surfaces. In a preferred embodiment, the angle of attack of the intermediate outer surfaces continually decrease from the first outer surface to the second outer surface. In a preferred embodiment, the angle of attack of the

intermediate outer surfaces decrease in steps from the first outer surface to the second outer surface. In a preferred embodiment, the angle of attack of the outer surfaces is defined by a parabolic equation. In a preferred embodiment, the angle of attack of the outer surfaces is defined by a parabolic equation.

5 A method of joining a first tubular member to a second tubular member also has been described that includes positioning at least a portion of the second tubular member within the first tubular member, radially expanding at least a portion of the second tubular member into contact with the first tubular member and radially expanding the first and second tubular members. The interior
10 diameter of the radially expanded second tubular member is substantially equal to the interior diameter of the radially unexpanded portion of the first tubular member. In a preferred embodiment, radially expanding at least a portion of the second tubular member into contact with the first tubular member includes increasing the interior diameter of the second tubular member from about 2% to
15 50%. In a preferred embodiment, radially expanding the first and second tubular members includes increasing the interior diameter of the first tubular member from about 0% to 40% and increasing the interior diameter of the second tubular member from about 2% to 50%. In a preferred embodiment, radially expanding the first and second tubular members includes plastically deforming the first and
20 second tubular members. In a preferred embodiment, radially expanding the first and second tubular members includes pressurizing an interior portion of the first and second tubular members. In a preferred embodiment, radially expanding the first and second tubular members includes displacing an expansion mandrel relative to the first and second tubular members. In a preferred embodiment, the
25 expansion mandrel is displaced in opposing directions.

 A tubular member also has been described that includes a first tubular member and a second tubular member coupled to the first tubular member. The first and second tubular members are coupled by the process of positioning at least a portion of the second tubular member within the first tubular member, radially
30 expanding at least a portion of the second tubular member into contact with the first tubular member and radially expanding the first and second tubular members. The interior diameter of the radially expanded second tubular member

is substantially equal to an interior diameter of the radially unexpanded portion of the first tubular member. In a preferred embodiment, radially expanding at least a portion of the second tubular member into contact with the first tubular member includes increasing the interior diameter of the second tubular member
5 from about 2% to 50%. In a preferred embodiment, radially expanding the first and second tubular members includes increasing the interior diameter of the first tubular member from about 0% to 40% and increasing the interior diameter of the second tubular member from about 2% to 50%. In a preferred embodiment, radially expanding the first and second tubular members includes plastically
10 deforming the first and second tubular members. In a preferred embodiment, radially expanding the first and second tubular members includes pressurizing an interior portion of the first and second tubular members. In a preferred embodiment, radially expanding the first and second tubular members includes displacing an expansion mandrel relative to the first and second tubular members.
15 In a preferred embodiment, the expansion mandrel is displaced in opposing directions.

A tubular member also has been described that includes a first tubular member and a second tubular member. The first tubular member includes an upper portion having an upper wall thickness and a lower portion having a lower
20 wall thickness. The second tubular member is coupled to the lower portion of the first tubular member. The interior diameters of the upper portion of the first tubular member and the second tubular member are substantially equal. In a preferred embodiment, the lower wall thickness is less than the upper wall thickness. In a preferred embodiment, the interface between the first and second
25 tubular members has a tensile pullout rating greater than the tensile yield point for the first and second tubular members. In a preferred embodiment, the interface between the first and second tubular members has a torsional failure point greater than the torsional yield point for the first and second tubular members. In a preferred embodiment, the interface between the first and second
30 tubular members has a pressure seal rating greater than the pressure seal rating for a conventional threaded connection including O-rings. In a preferred embodiment, the interface between the first and second tubular members has a

burst capacity greater than the burst capacity for the first and second tubular members.

An apparatus also has been described that includes a first tubular member, a second tubular member positioned in overlapping relation to the first tubular member, an expansion mandrel positioned within the first tubular member including one or more outer surfaces for radially expanding the first and second tubular members, a support member coupled to the expansion mandrel for supporting the expansion mandrel, a first fluid conduit positioned within the expansion mandrel and the support member, a packer sealingly coupled to the first tubular member and slidingly and sealingly coupled to the support member, a second fluid conduit coupled to the packer and a pump fluidically coupled to the second fluid conduit. In a preferred embodiment, the apparatus further includes an annular region defined by the packer, the expansion mandrel, the support member and the first tubular member, wherein the second fluid conduit is fluidically coupled to the annular region. In a preferred embodiment, the first fluid conduit is fluidically coupled to the interior of the second tubular member. In a preferred embodiment, the maximum outside diameter of the expansion mandrel is substantially equal to the inside diameter of the first tubular member. In a preferred embodiment, the expansion mandrel includes a pair of oppositely positioned outer conical surfaces. In a preferred embodiment, the apparatus further includes a slip joint for permitting the expansion mandrel to be displaced relative to the support member.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. In some instances, some features of the present invention may be employed without a corresponding use of the other features. Accordingly, it is appropriate that the appended claims be construed broadly and in a manner consistent with the scope of the invention.

Claims

- 1 1. An expandable tubular member, including:
 - 2 a first tubular section having a first outer diameter;
 - 3 an intermediate tubular section coupled to the first tubular section having
 - 4 an intermediate outer diameter; and
 - 5 a second tubular section having a second outer diameter coupled to the
 - 6 intermediate tubular section having a second outer diameter;
 - 7 wherein the first and second outer diameters are greater than the
 - 8 intermediate outer diameter.

- 1 2. A method of fabricating an expandable tubular member, comprising:
 - 2 providing a tubular member having a first end, a second end, and an
 - 3 intermediate portion; and
 - 4 radially expanding the first end and the second end of the tubular member.

- 1 3. An apparatus, comprising:
 - 2 a tubular member formed by the process of radially expanding an
 - 3 unexpanded tubular member into contact with an approximately
 - 4 cylindrical passage using an expansion cone, the unexpanded tubular
 - 5 member including:
 - 6 a first tubular section having a first outer diameter;
 - 7 an intermediate tubular section coupled to the first tubular
 - 8 section having an intermediate outer diameter; and
 - 9 a second tubular section having a second outer diameter
 - 10 coupled to the intermediate tubular section having a
 - 11 second outer diameter;
 - 12 wherein the first and second outer diameters are greater than
 - 13 the intermediate outer diameter.

- 1 4. A method of joining a first tubular member to a second tubular member,
 - 2 comprising:

3 positioning at least a portion of the second tubular member within the first
4 tubular member;
5 radially expanding at least a portion of the second tubular member into
6 contact with the first tubular member; and
7 radially expanding the first and second tubular members;
8 wherein the interior diameter of the radially expanded second tubular
9 member is substantially equal to the interior diameter of the radially
10 unexpanded portion of the first tubular member.

1 5. A tubular member, comprising:
2 a first tubular member; and
3 a second tubular member coupled to the first tubular member;
4 wherein the first and second tubular members are coupled by the process
5 of:
6 positioning at least a portion of the second tubular member within
7 the first tubular member;
8 radially expanding at least a portion of the second tubular member
9 into contact with the first tubular member; and
10 radially expanding the first and second tubular members;
11 wherein the interior diameter of the radially expanded second
12 tubular member is substantially equal to an interior diameter
13 of the radially unexpanded portion of the first tubular
14 member.

1 6. A tubular member, comprising:
2 a first tubular member, including:
3 an upper portion having an upper wall thickness; and
4 a lower portion having a lower wall thickness; and
5 a second tubular member coupled to the lower portion of the first tubular
6 member;
7 wherein the interior diameters of the upper portion of the first tubular
8 member and the second tubular member are substantially equal.

- 1 7. An apparatus, comprising:
2 a first tubular member;
3 a second tubular member positioned in overlapping relation to the first
4 tubular member;
5 an expansion mandrel positioned within the first tubular member including
6 one or more outer surfaces for radially expanding the first and
7 second tubular members;
8 a support member coupled to the expansion mandrel for supporting the
9 expansion mandrel;
10 a first fluid conduit positioned within the expansion mandrel and the
11 support member;
12 a packer sealingly coupled to the first tubular member and slidingly and
13 sealingly coupled to the support member;
14 a second fluid conduit coupled to the packer; and
15 a pump fluidically coupled to the second fluid conduit.

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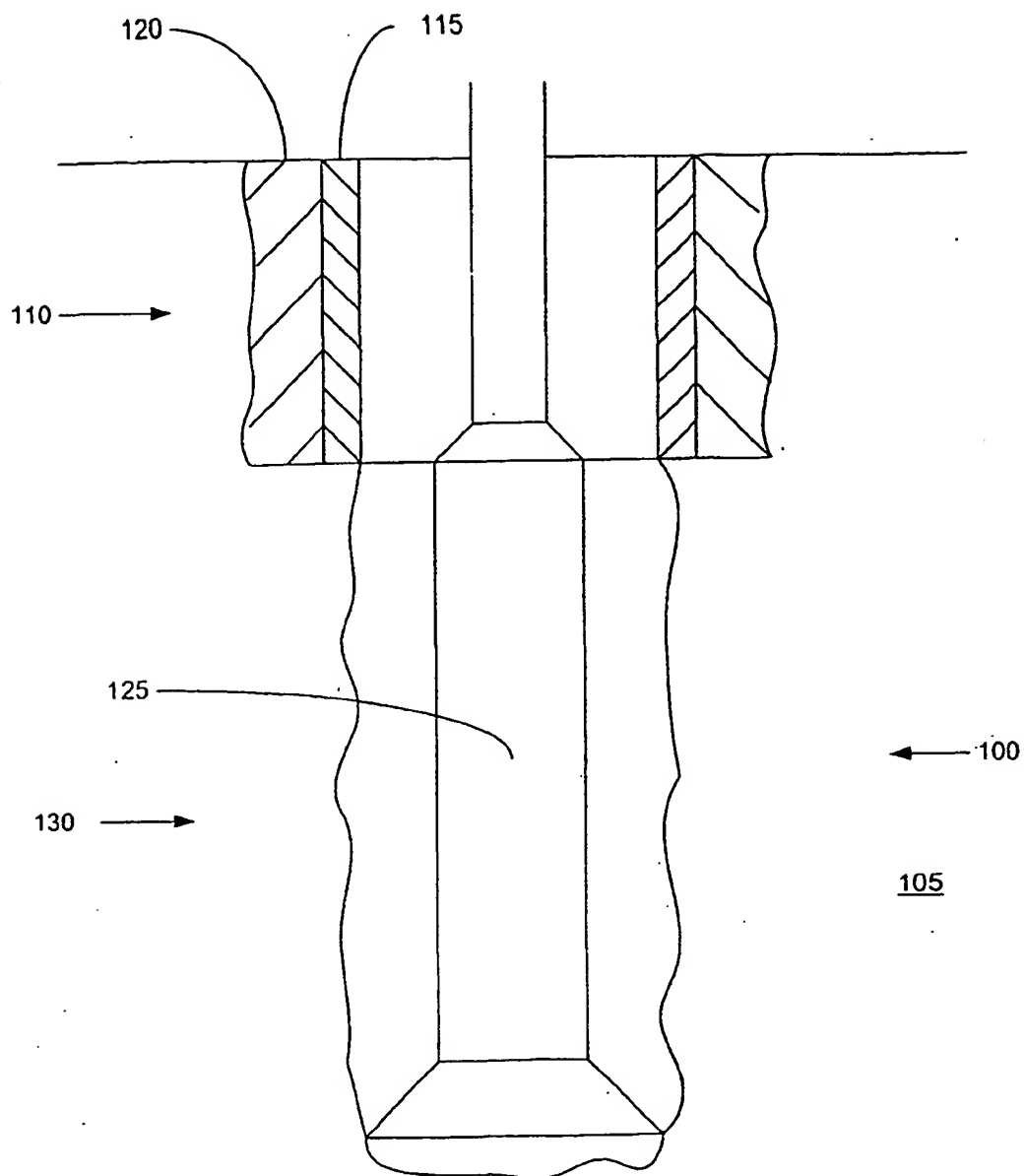


FIGURE 1

be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the intermediate casing 1530 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

5 In a preferred embodiment, the intermediate casing 1530 is coupled to the thick wall casing 1510 by expanding at least a portion of the intermediate casing 1530 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to Figs. 1-11f. In an alternative preferred embodiment, the entire length of the overlap of the
10 intermediate casing 1530 with the thick wall casing 1510 contacts the inner surface of the thick wall casing 1510. The contact pressure of the interface between the intermediate casing 1530 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. In a preferred embodiment, the contact pressure between the intermediate casing 1530 and the thick wall casing 1510
15 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads experienced during drilling and production operations.

As illustrated in Fig. 13, in a particularly preferred embodiment, the upper
20 end of the intermediate casing 1530 includes one or more sealing members 1560 that provide a gaseous and fluidic seal between the expanded end of the intermediate casing 1530 and the interior wall of the thick wall casing 1510. The sealing members 1560 may comprise any number of conventional commercially available seals such as, for example, plastic, lead, rubber, Teflon or epoxy, modified
25 in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 1560 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide a hydraulic seal and a load bearing interference fit between the tubular members.

In a preferred embodiment, the contact pressure of the interface between
30 the expanded end of the intermediate casing 1530 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the sealing

members 1560 and also optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production operations.

The inner casing 1535 may be coupled to the outer casing 1520 or the thick wall casing 1510. In a preferred embodiment, the inner casing 1535 is coupled to the thick wall casing 1510. The inner casing 1535 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the inner casing 1535 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

In a preferred embodiment, the inner casing 1535 is coupled to the outer casing 1520 by expanding at least a portion of the inner casing 1535 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to Figs. 1-11f. In an alternative preferred embodiment, the entire length of the overlap of the inner casing 1535 with the thick wall casing 1510 and intermediate casing 1530 contacts the inner surfaces of the thick wall casing 1510 and intermediate casing 1530. The contact pressure of the interface between the inner casing 1535 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. In a preferred embodiment, the contact pressure between the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to ensure that the joint will withstand typical extremes of tensile and compressive loads that are commonly experienced during drilling and production operations.

As illustrated in Fig. 13, in a particularly preferred embodiment, the upper end of the inner casing 1535 includes one or more sealing members 1570 that provide a gaseous and fluidic seal between the expanded end of the inner casing 1535 and the interior wall of the thick wall casing 1510. The sealing members 1570 may comprise any number of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 1570 comprise seals molded from StrataLock epoxy available from

Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit. In a preferred embodiment, the contact pressure of the interface between the expanded end of the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate
5 the sealing members 1570 and also to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production operations.

In an alternative embodiment, the inner casings, 1520, 1530 and 1535, may be coupled to a previously positioned tubular member that is in turn coupled to the
10 outer casing 1510. More generally, the present preferred embodiments may be used to form a concentric arrangement of tubular members.

Referring now to Figures 14a, 14b, 14c, 14d, 14e and 14f, a preferred embodiment of a method and apparatus for forming a mono-diameter well casing within a subterranean formation will now be described.

As illustrated in Fig. 14a, a wellbore 1600 is positioned in a subterranean
15 formation 1605. A first section of casing 1610 is formed in the wellbore 1600. The first section of casing 1610 includes an annular outer body of cement 1615 and a tubular section of casing 1620. The first section of casing 1610 may be formed in the wellbore 1600 using conventional methods and apparatus. In a preferred
20 embodiment, the first section of casing 1610 is formed using one or more of the methods and apparatus described above with reference to Figs. 1-13 or below with reference to Figs. 14b-17b.

The annular body of cement 1615 may comprise any number of conventional commercially available cement, or other load bearing, compositions. Alternatively,
25 the body of cement 1615 may be omitted or replaced with an epoxy mixture.

The tubular section of casing 1620 preferably includes an upper end 1625 and a lower end 1630. Preferably, the lower end 1625 of the tubular section of casing 1620 includes an outer annular recess 1635 extending from the lower end
30 1630 of the tubular section of casing 1620. In this manner, the lower end 1625 of the tubular section of casing 1620 includes a thin walled section 1640. In a preferred embodiment, an annular body 1645 of a compressible material is coupled to and at least partially positioned within the outer annular recess 1635. In this

manner, the body of compressible material 1645 surrounds at least a portion of the thin walled section 1640.

The tubular section of casing 1620 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, carbon steel, low alloy steel, fiberglass or plastics. In a preferred embodiment, the tubular section of casing 1620 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills. The wall thickness of the thin walled section 1640 may range from about 0.125 to 1.5 inches. In a preferred embodiment, the wall thickness of the thin walled section 1640 ranges from 0.25 to 1.0 inches in order to optimally provide burst strength for typical operational conditions while also minimizing resistance to radial expansion. The axial length of the thin walled section 1640 may range from about 120 to 2400 inches. In a preferred embodiment, the axial length of the thin walled section 1640 ranges from about 240 to 480 inches.

The annular body of compressible material 1645 helps to minimize the radial force required to expand the tubular casing 1620 in the overlap with the tubular member 1715, helps to create a fluidic seal in the overlap with the tubular member 1715, and helps to create an interference fit sufficient to permit the tubular member 1715 to be supported by the tubular casing 1620. The annular body of compressible material 1645 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or lead tubes. In a preferred embodiment, the annular body of compressible material 1645 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint while also having compliance to thereby minimize the radial force required to expand the tubular casing. The wall thickness of the annular body of compressible material 1645 may range from about 0.05 to 0.75 inches. In a preferred embodiment, the wall thickness of the annular body of compressible material 1645 ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible zone, minimize the radial forces required to expand the tubular

casing, provide thickness for casing strings to provide contact with the inner surface of the wellbore upon radial expansion, and provide an hydraulic seal.

As illustrated in Fig. 14b, in order to extend the wellbore 1600 into the subterranean formation 1605, a drill string is used in a well known manner to drill
5 out material from the subterranean formation 1605 to form a new wellbore section 1650. The diameter of the new section 1650 is preferably equal to or greater than the inner diameter of the tubular section of casing 1620.

As illustrated in Fig. 14c, a preferred embodiment of an apparatus 1700 for forming a mono-diameter wellbore casing in a subterranean formation is then
10 positioned in the new section 1650 of the wellbore 1600. The apparatus 1700 preferably includes a support member 1705, an expandable mandrel or pig 1710, a tubular member 1715, a shoe 1720, slips 1725, a fluid passage 1730, one or more fluid passages 1735, a fluid passage 1740, a first compressible annular body 1745, a second compressible annular body 1750, and a pressure chamber 1755.

15 The support member 1705 supports the apparatus 1700 within the wellbore 1600. The support member 1705 is coupled to the mandrel 1710, the tubular member 1715, the shoe 1720, and the slips 1725. The support member 1075 preferably comprises a substantially hollow tubular member. The fluid passage 1730 is positioned within the support member 1705. The fluid passages 1735
20 fluidicly couple the fluid passage 1730 with the pressure chamber 1755. The fluid passage 1740 fluidicly couples the fluid passage 1730 with the region outside of the apparatus 1700.

The support member 1705 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield
25 country tubular goods, stainless steel, low alloy steel, carbon steel, 13 chromium steel, fiberglass, or other high strength materials. In a preferred embodiment, the support member 1705 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide operational strength and facilitate the use of other standard oil exploration
30 handling equipment. In a preferred embodiment, at least a portion of the support member 1705 comprises coiled tubing or a drill pipe. In a particularly preferred

embodiment, the support member 1705 includes a load shoulder 1820 for supporting the mandrel 1710 when the pressure chamber 1755 is unpressurized.

The mandrel 1710 is supported by and slidingly coupled to the support member 1705 and the shoe 1720. The mandrel 1710 preferably includes an upper
5 portion 1760 and a lower portion 1765. Preferably, the upper portion 1760 of the mandrel 1710 and the support member 1705 together define the pressure chamber 1755. Preferably, the lower portion 1765 of the mandrel 1710 includes an expansion member 1770 for radially expanding the tubular member 1715.

In a preferred embodiment, the upper portion 1760 of the mandrel 1710
10 includes a tubular member 1775 having an inner diameter greater than an outer diameter of the support member 1705. In this manner, an annular pressure chamber 1755 is defined by and positioned between the tubular member 1775 and the support member 1705. The top 1780 of the tubular member 1775 preferably includes a bearing and a seal for sealing and supporting the top 1780 of the tubular
15 member 1775 against the outer surface of the support member 1705. The bottom 1785 of the tubular member 1775 preferably includes a bearing and seal for sealing and supporting the bottom 1785 of the tubular member 1775 against the outer surface of the support member 1705 or shoe 1720. In this manner, the mandrel 1710 moves in an axial direction upon the pressurization of the pressure chamber
20 1755.

The lower portion 1765 of the mandrel 1710 preferably includes an expansion member 1770 for radially expanding the tubular member 1715 during the pressurization of the pressure chamber 1755. In a preferred embodiment, the expansion member is expandable in the radial direction. In a preferred
25 embodiment, the inner surface of the lower portion 1765 of the mandrel 1710 mates with and slides with respect to the outer surface of the shoe 1720. The outer diameter of the expansion member 1770 may range from about 90 to 100 % of the inner diameter of the tubular casing 1620. In a preferred embodiment, the outer diameter of the expansion member 1770 ranges from about 95 to 99 % of the inner
30 diameter of the tubular casing 1620. The expansion member 1770 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, titanium or other

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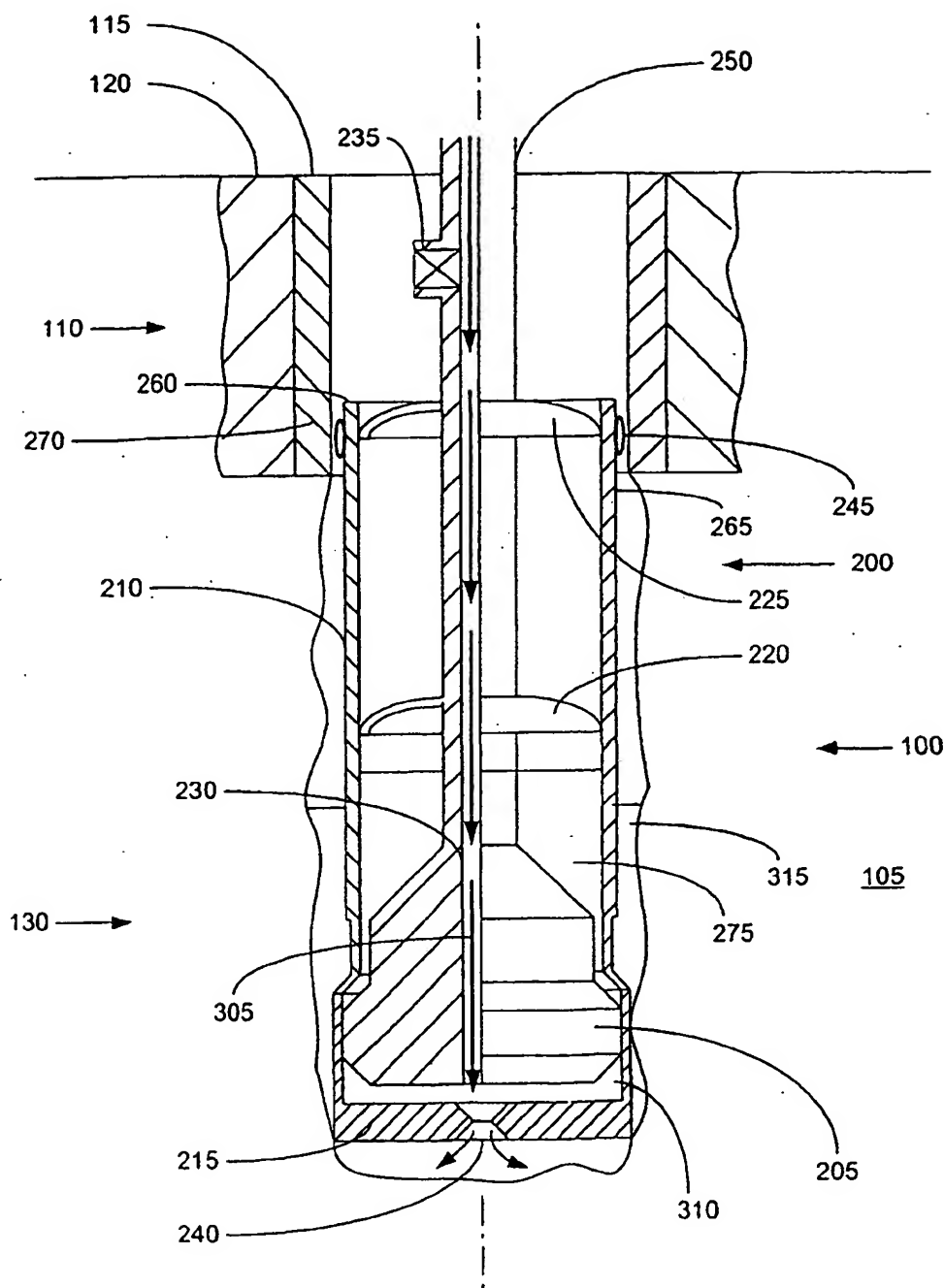


FIGURE 3a

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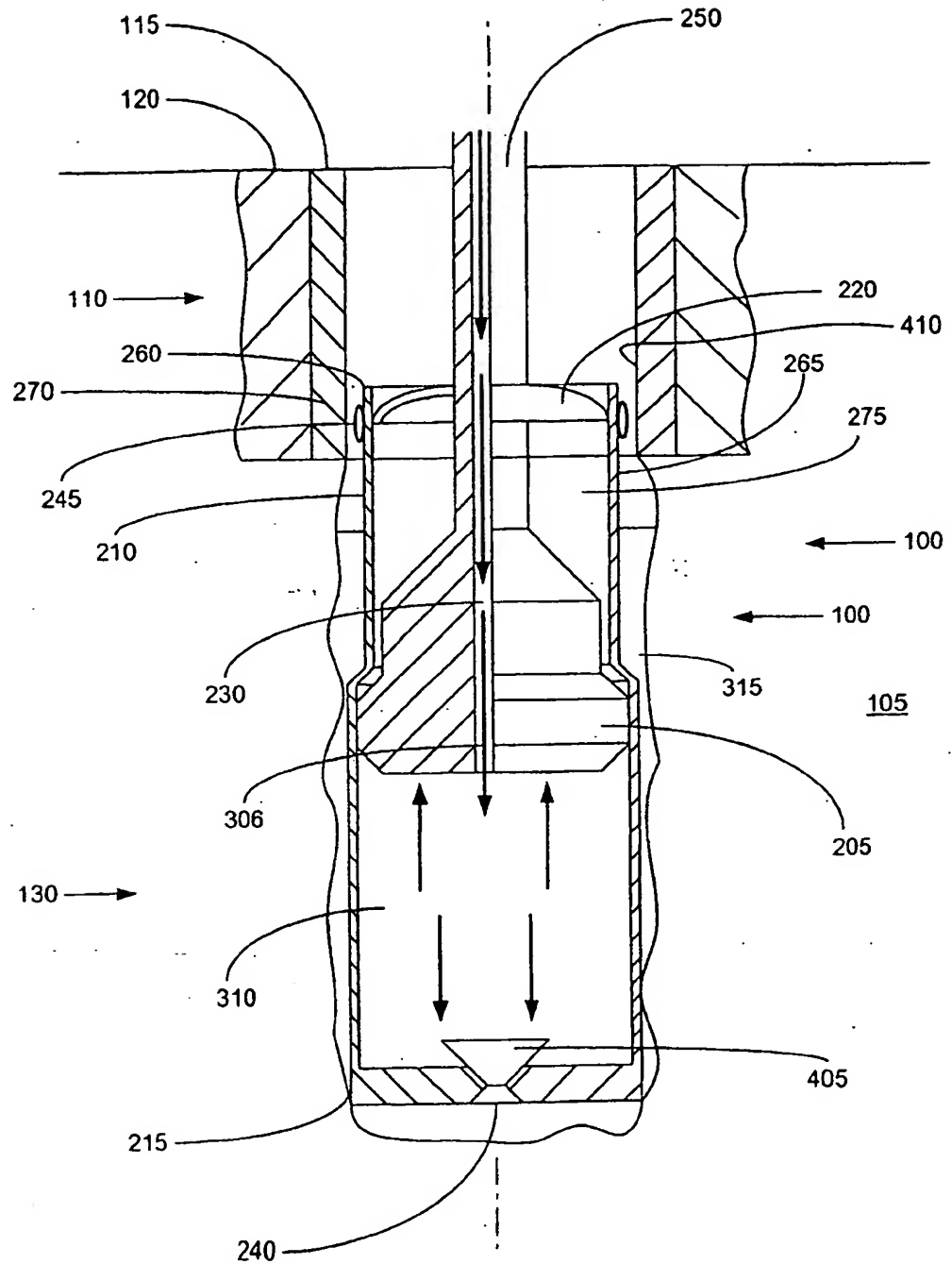


FIGURE 4

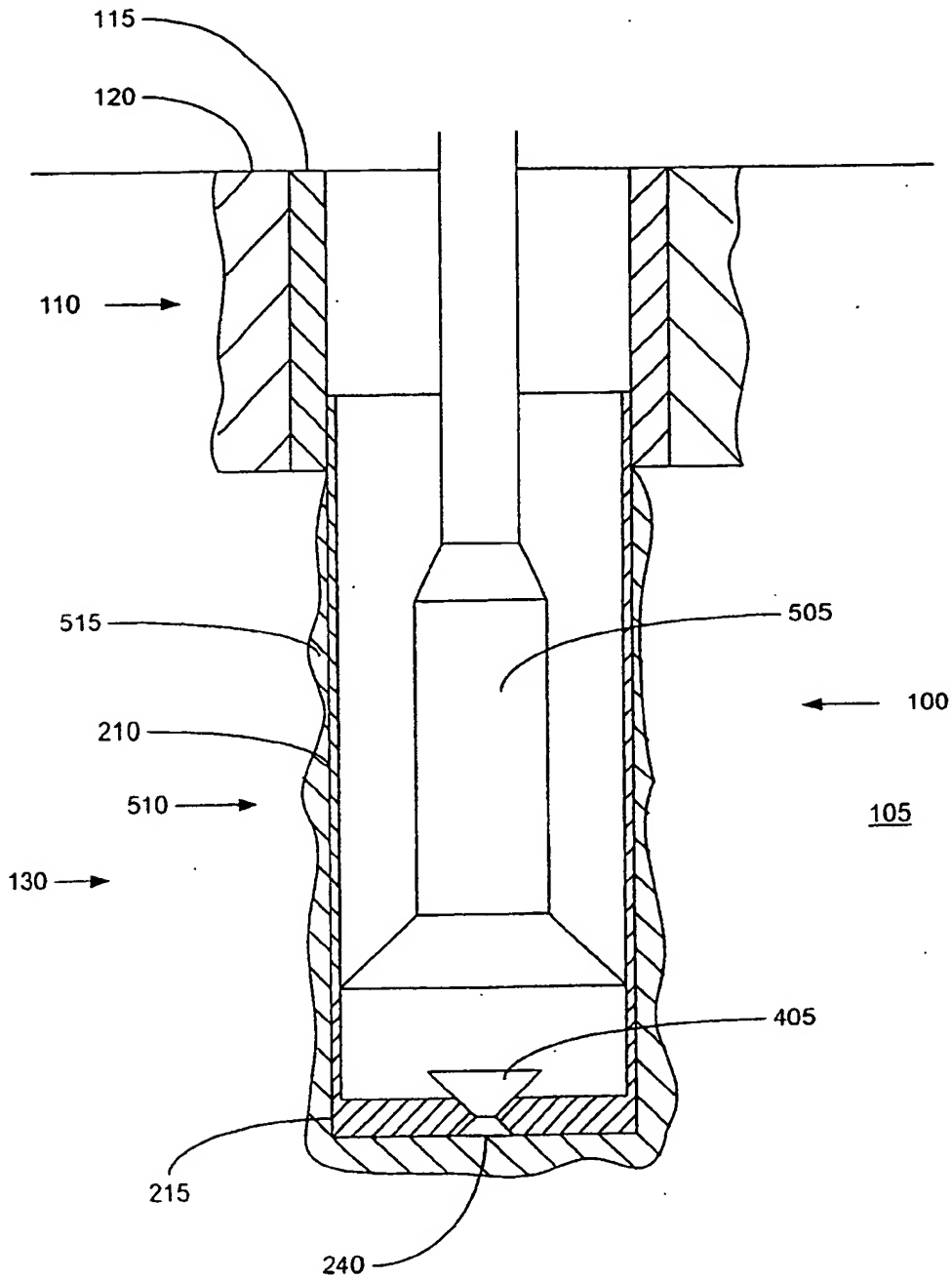


FIGURE 5

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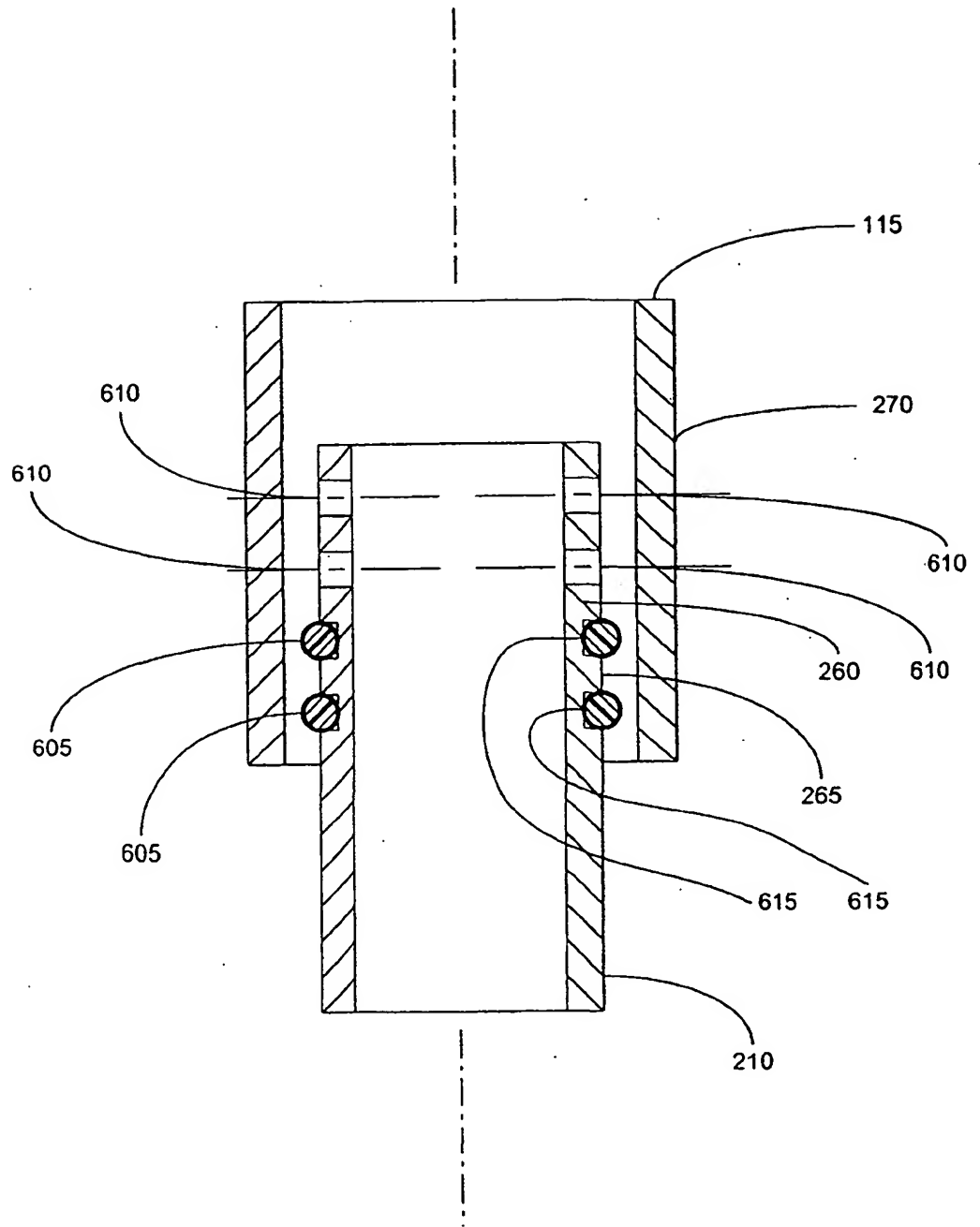


FIGURE 6

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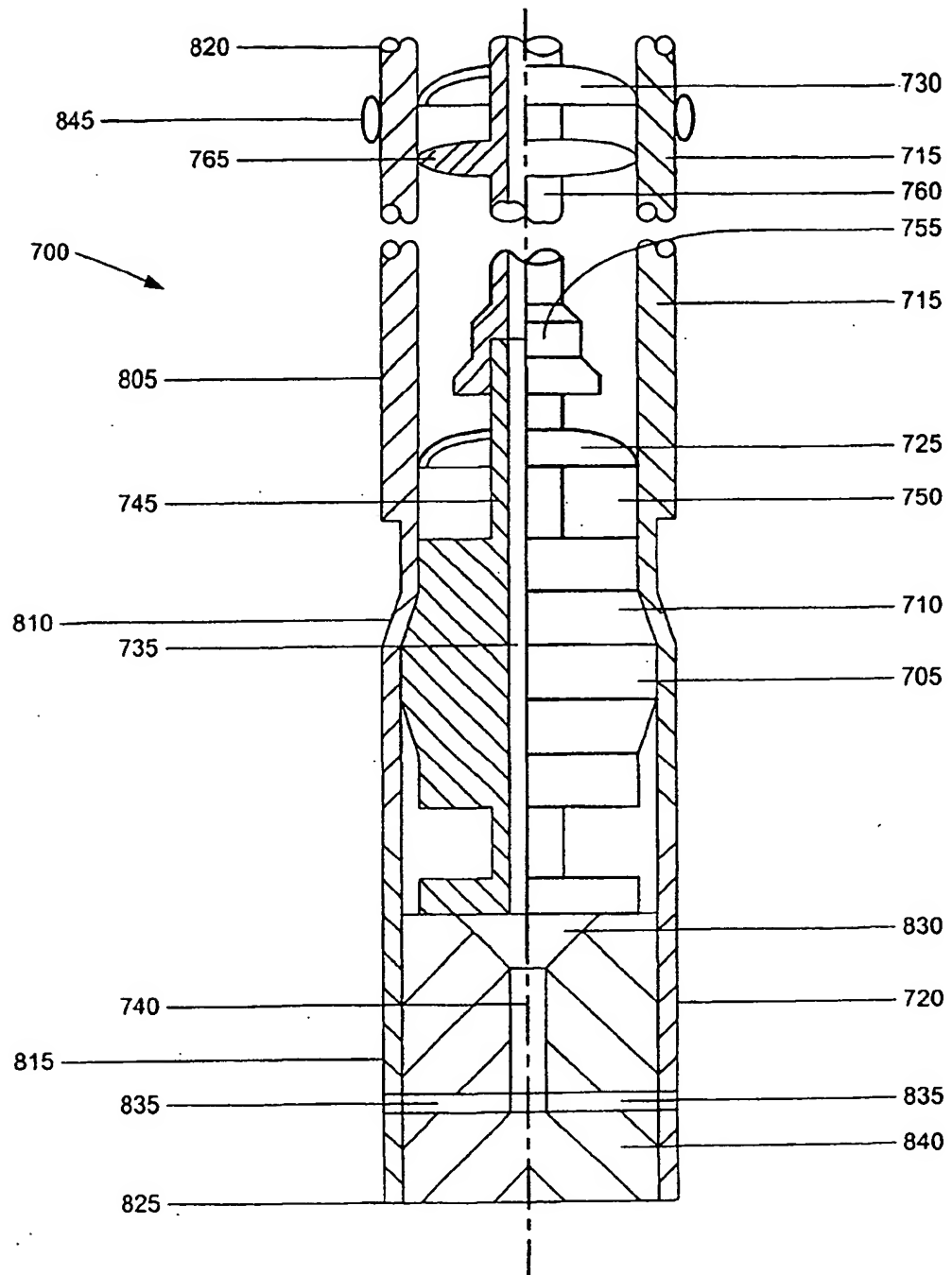


FIGURE 7

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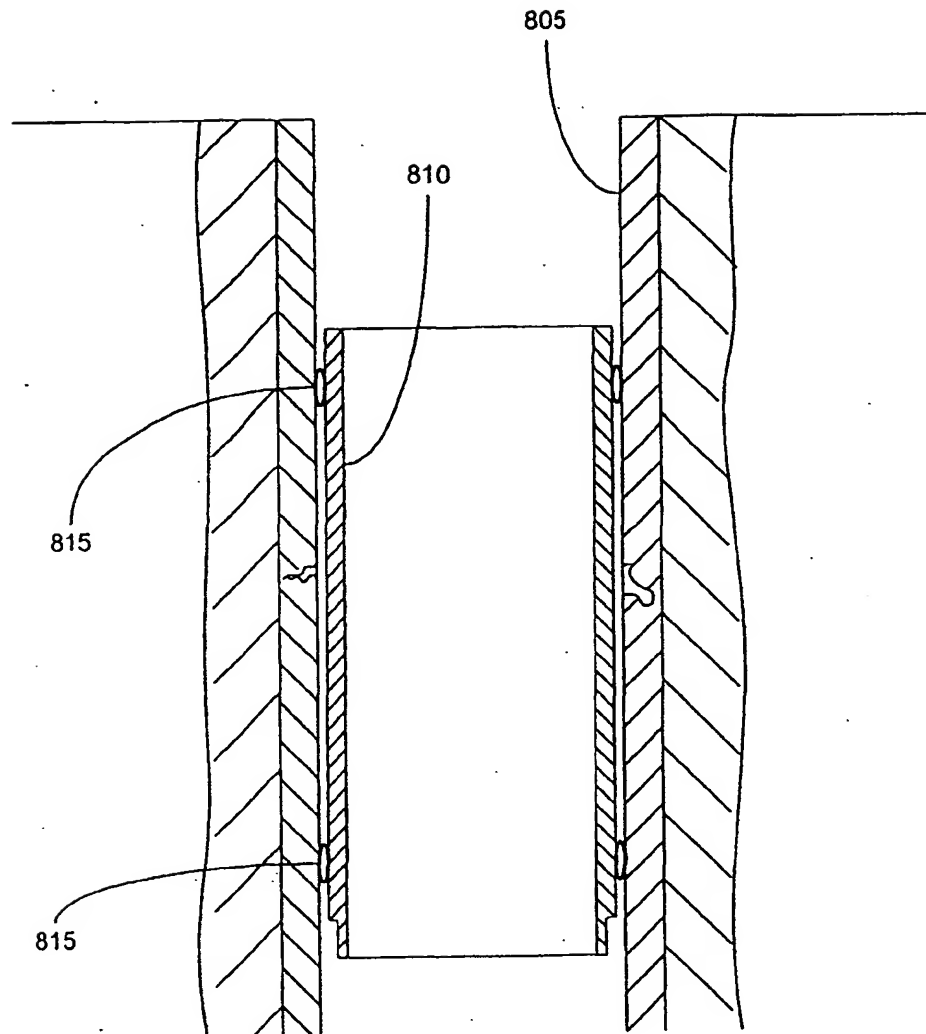


FIGURE 8

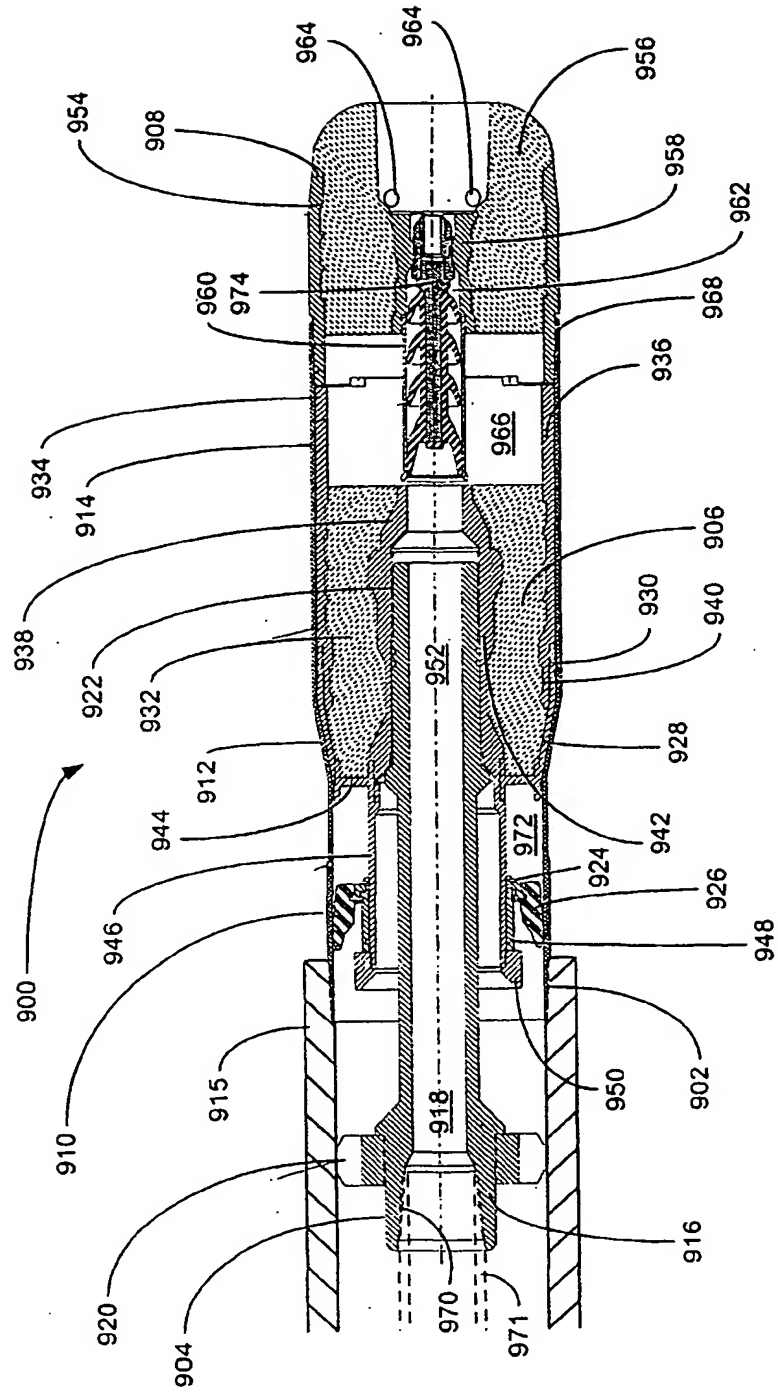


FIGURE 9

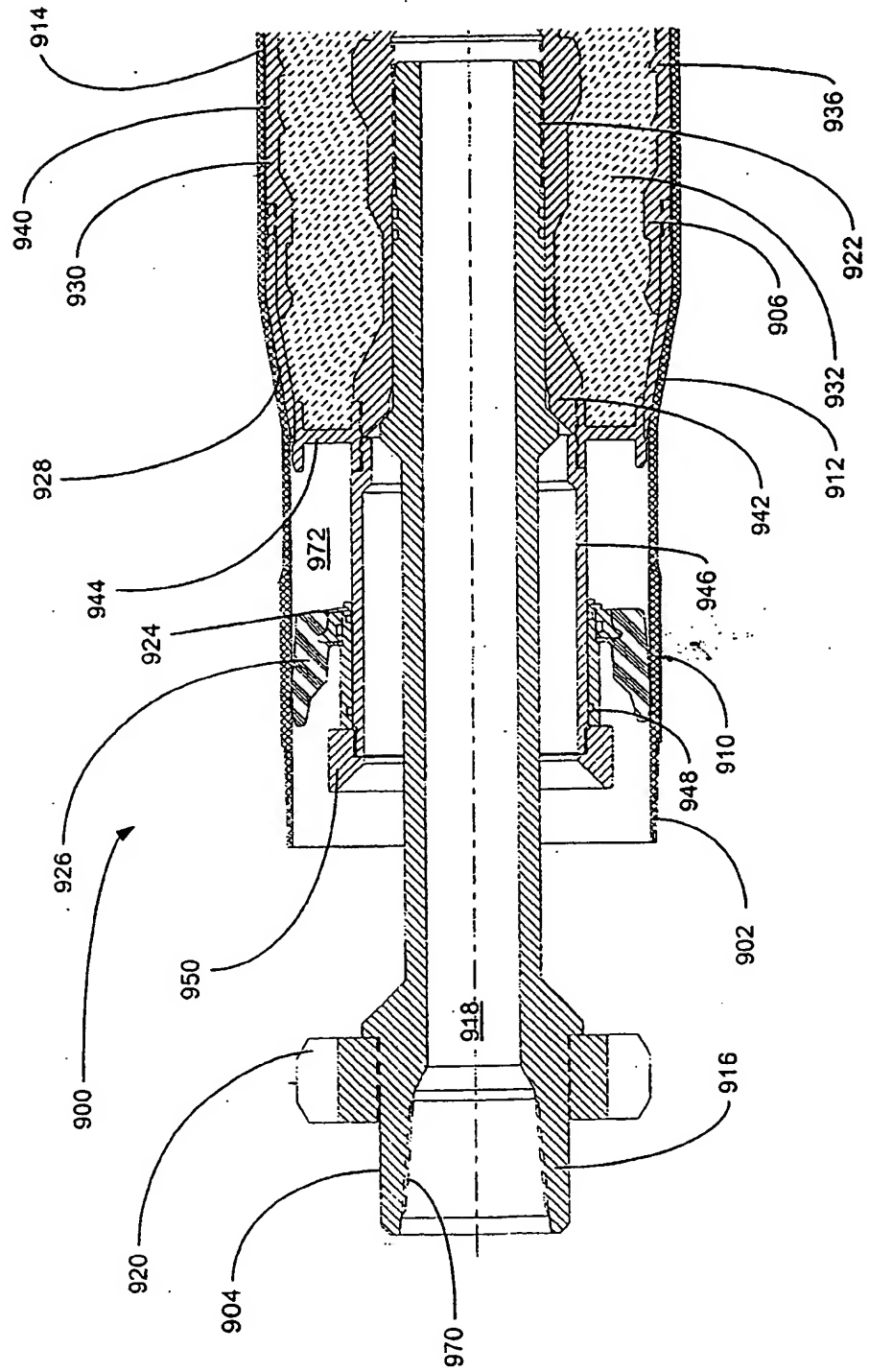


FIGURE 9a

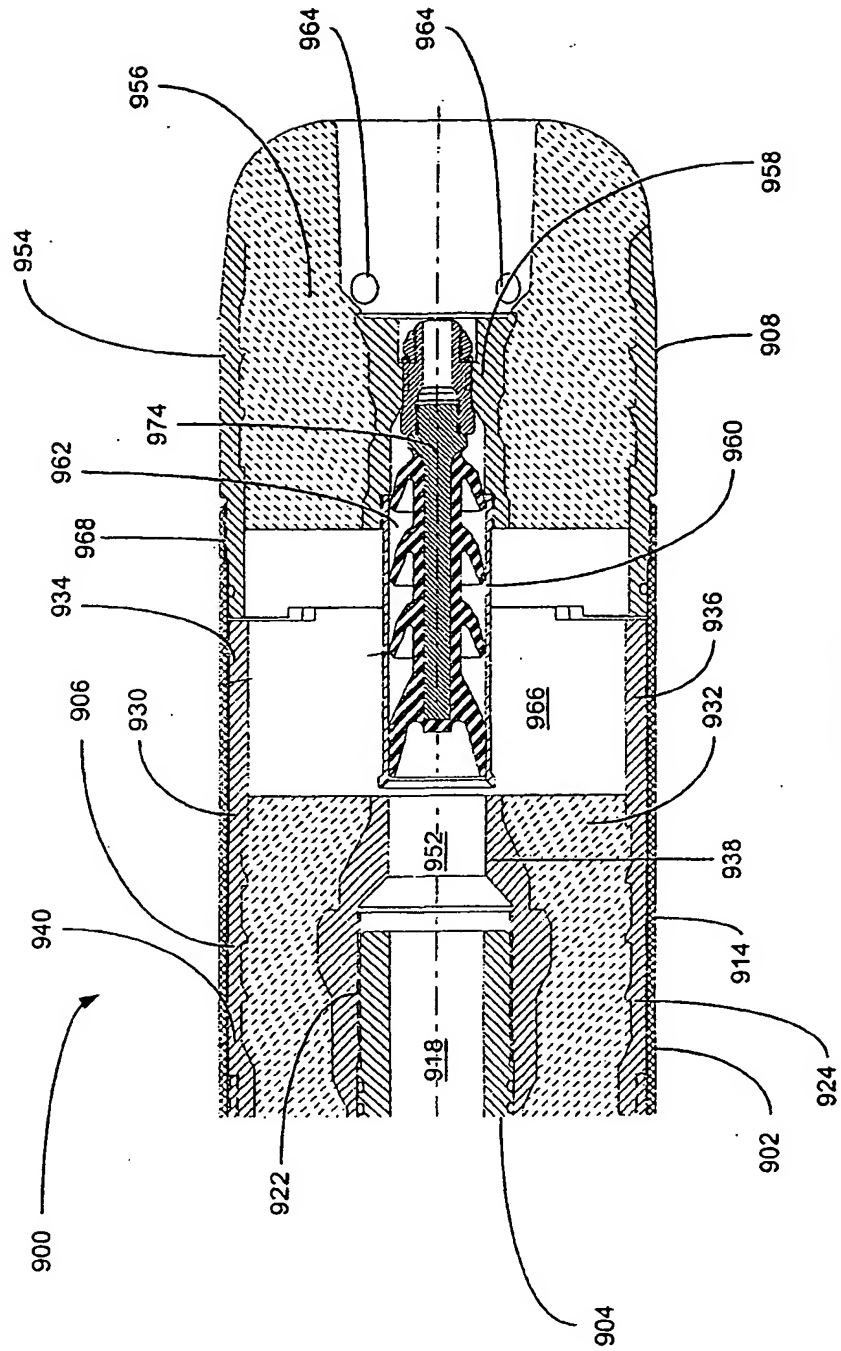


FIGURE 9b

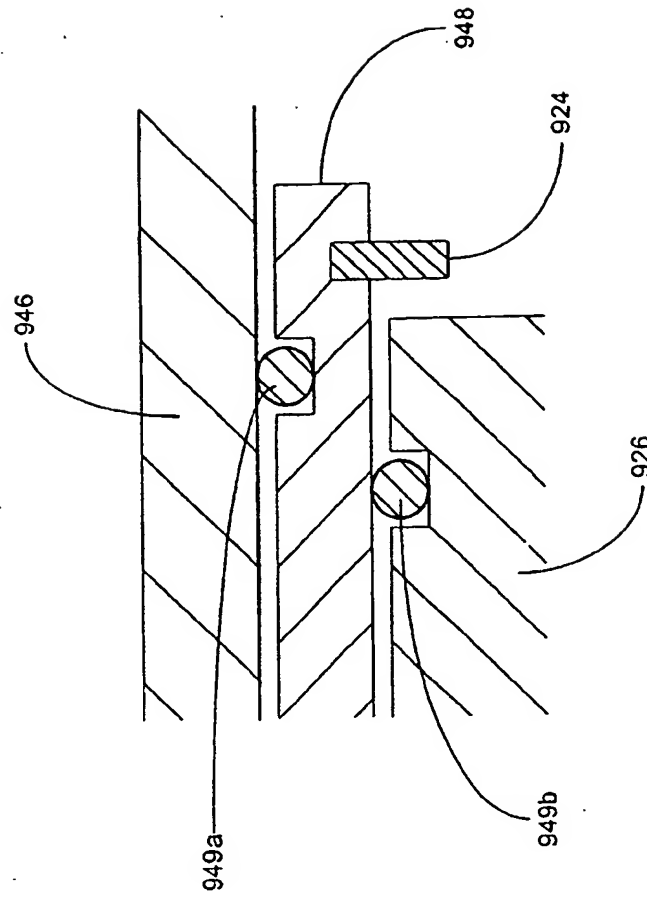


FIGURE 9C

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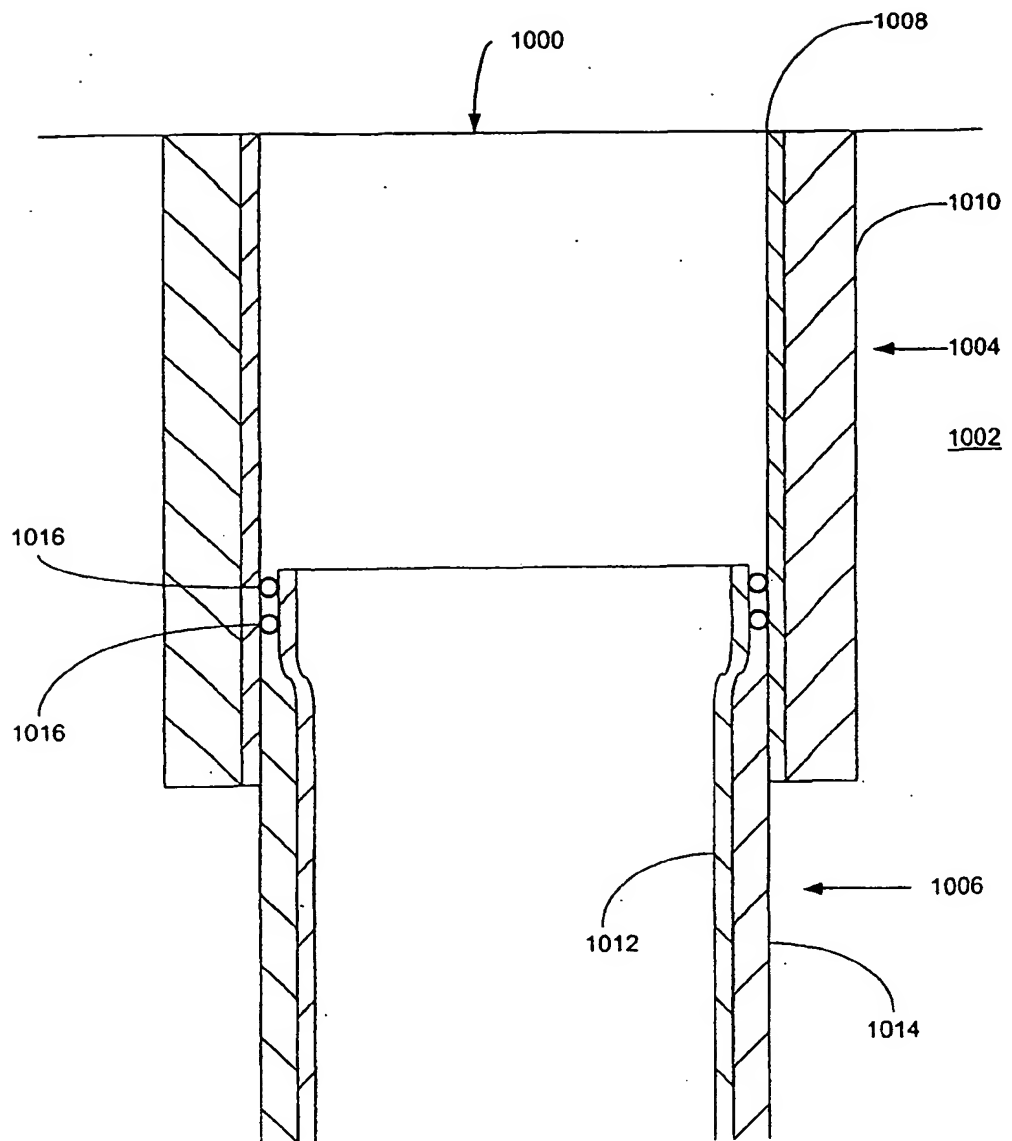


FIGURE 10a

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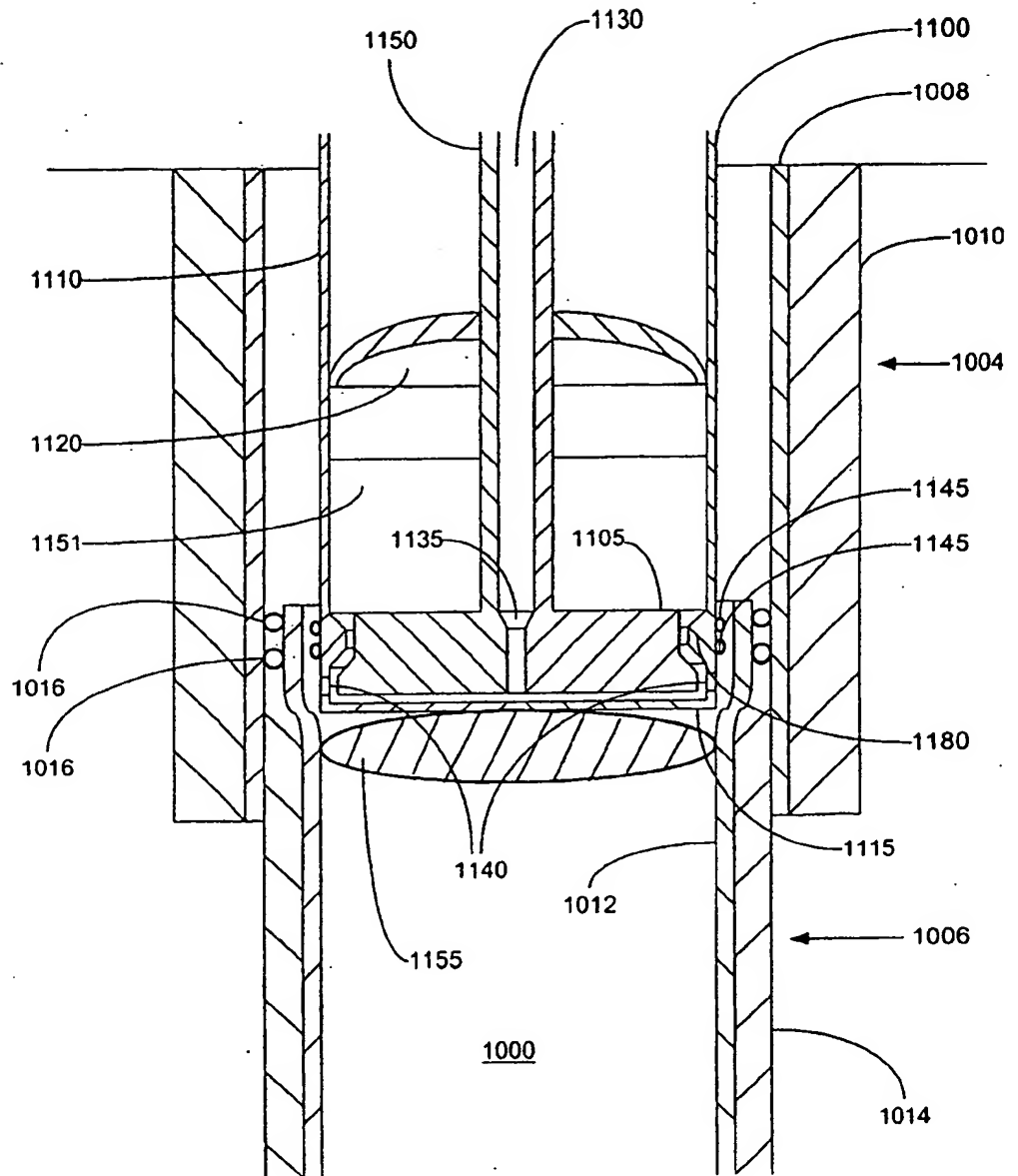


FIGURE 10b

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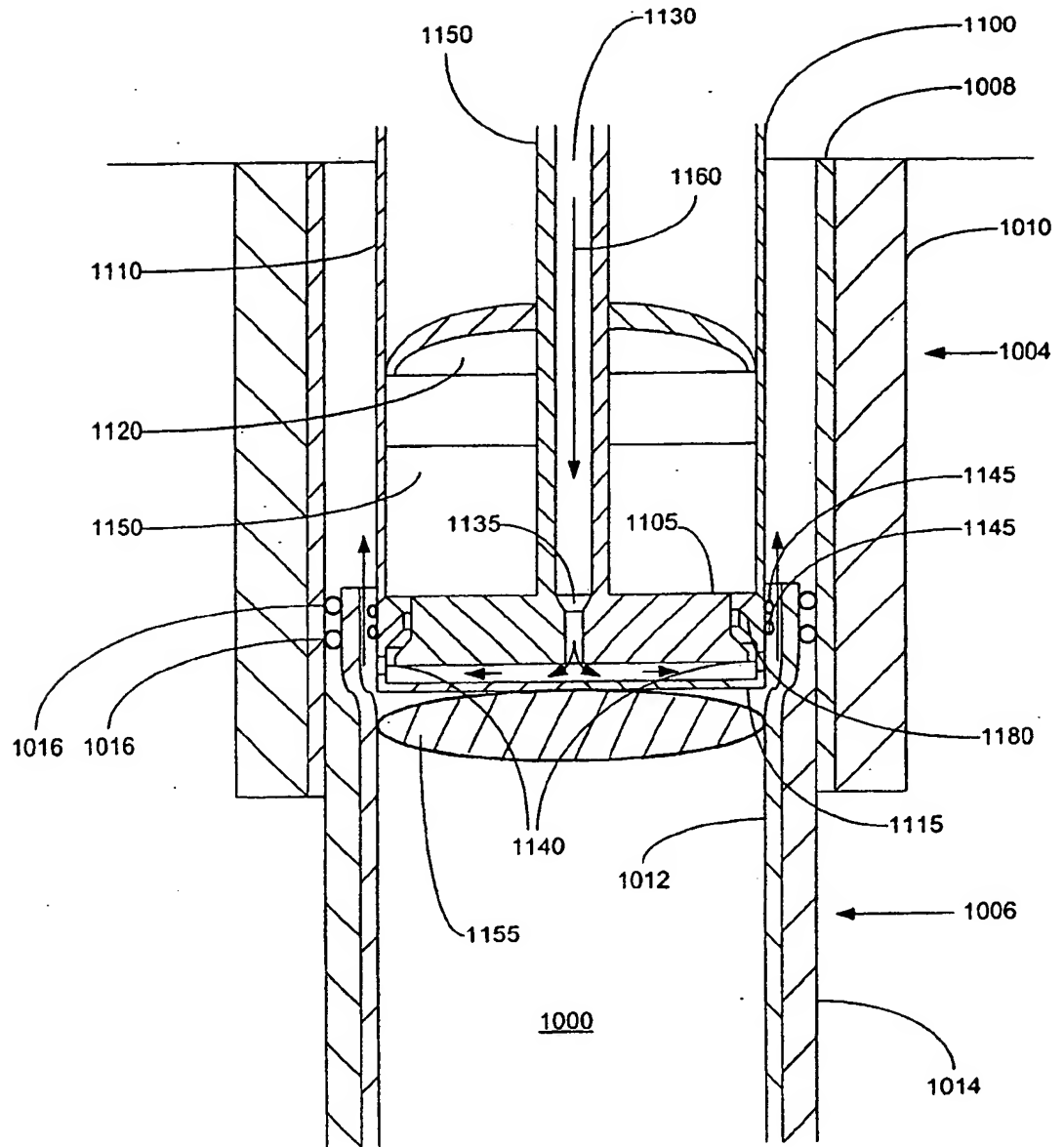


FIGURE 10c

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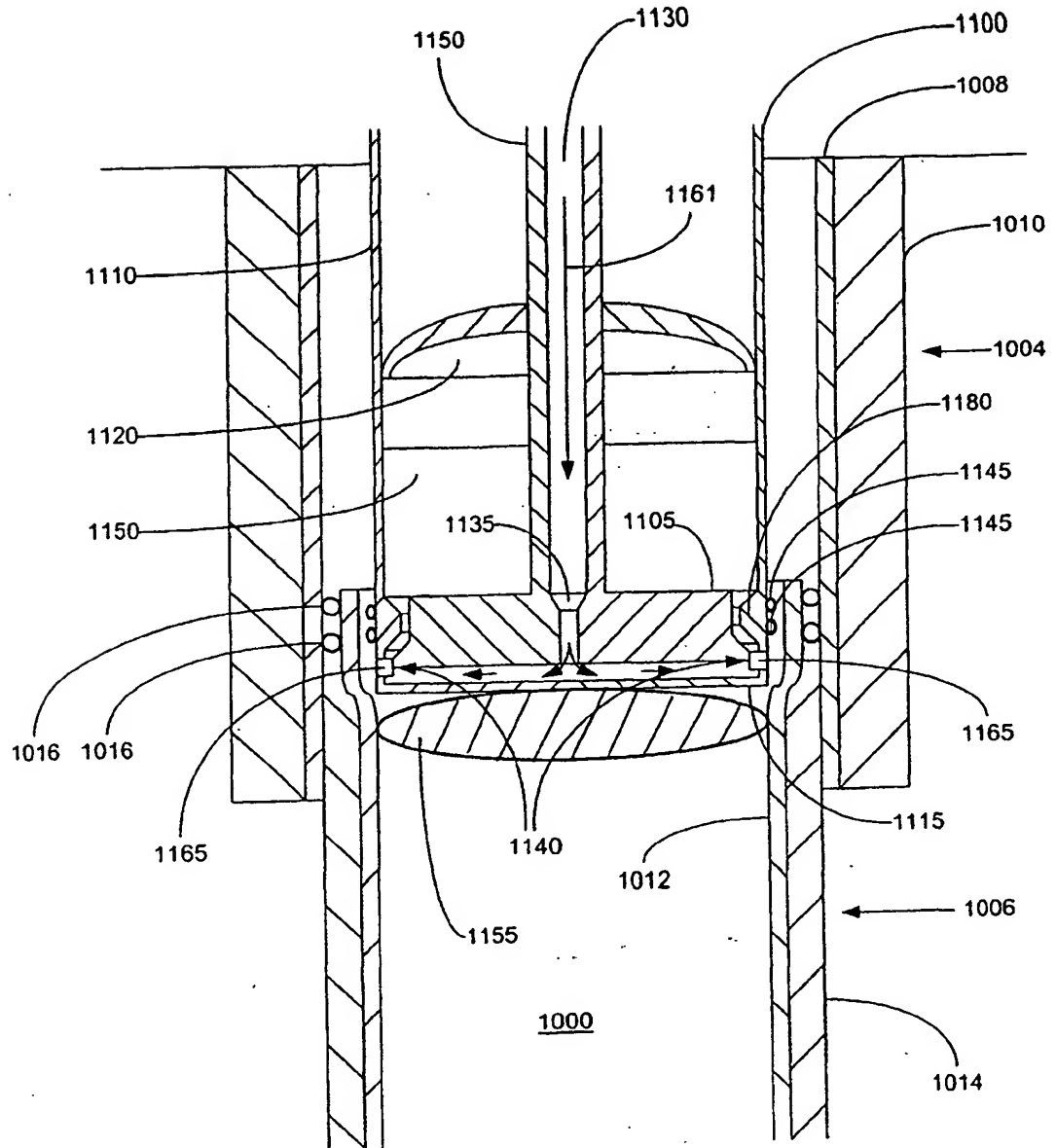


FIGURE 10d

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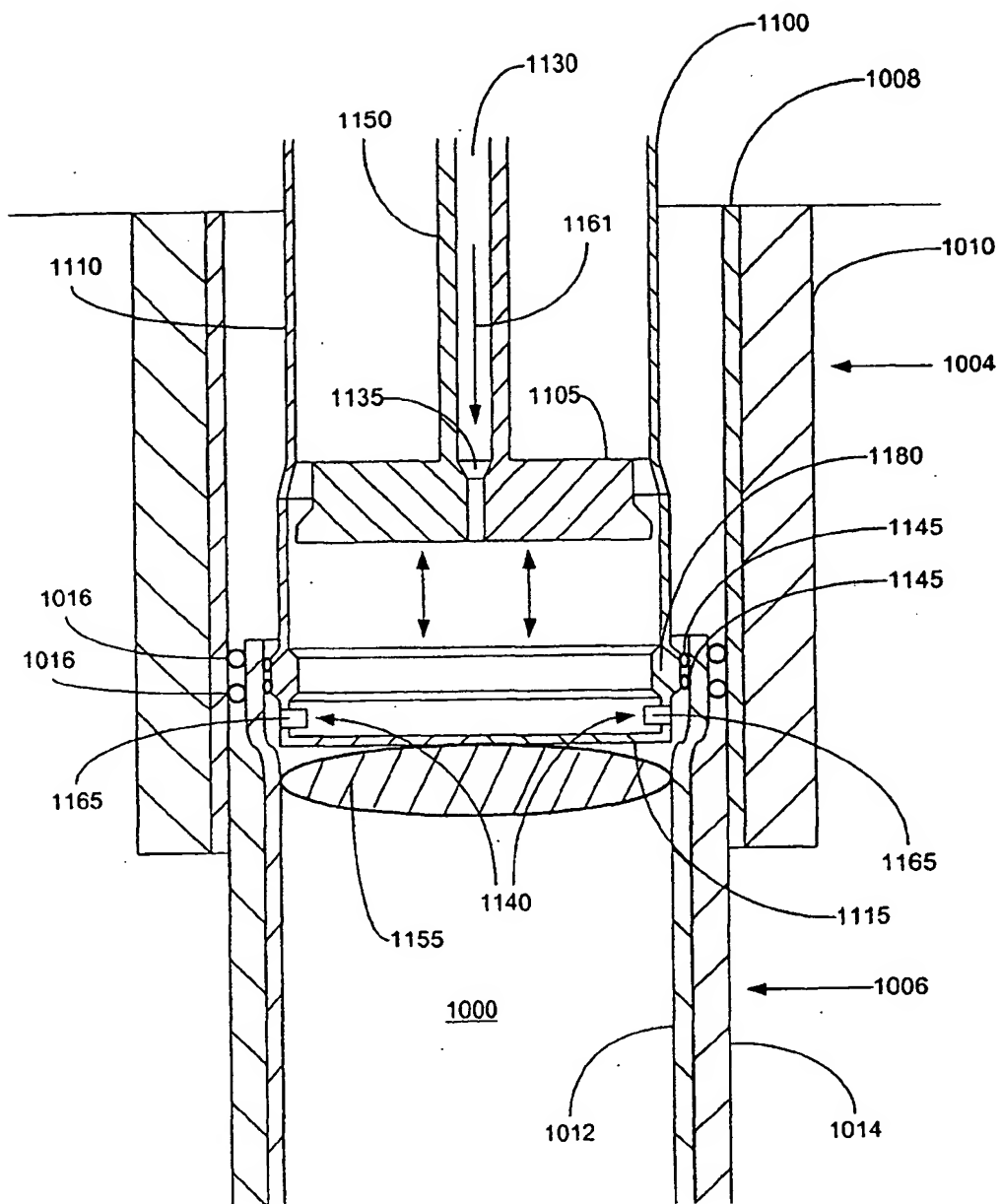


FIGURE 10e

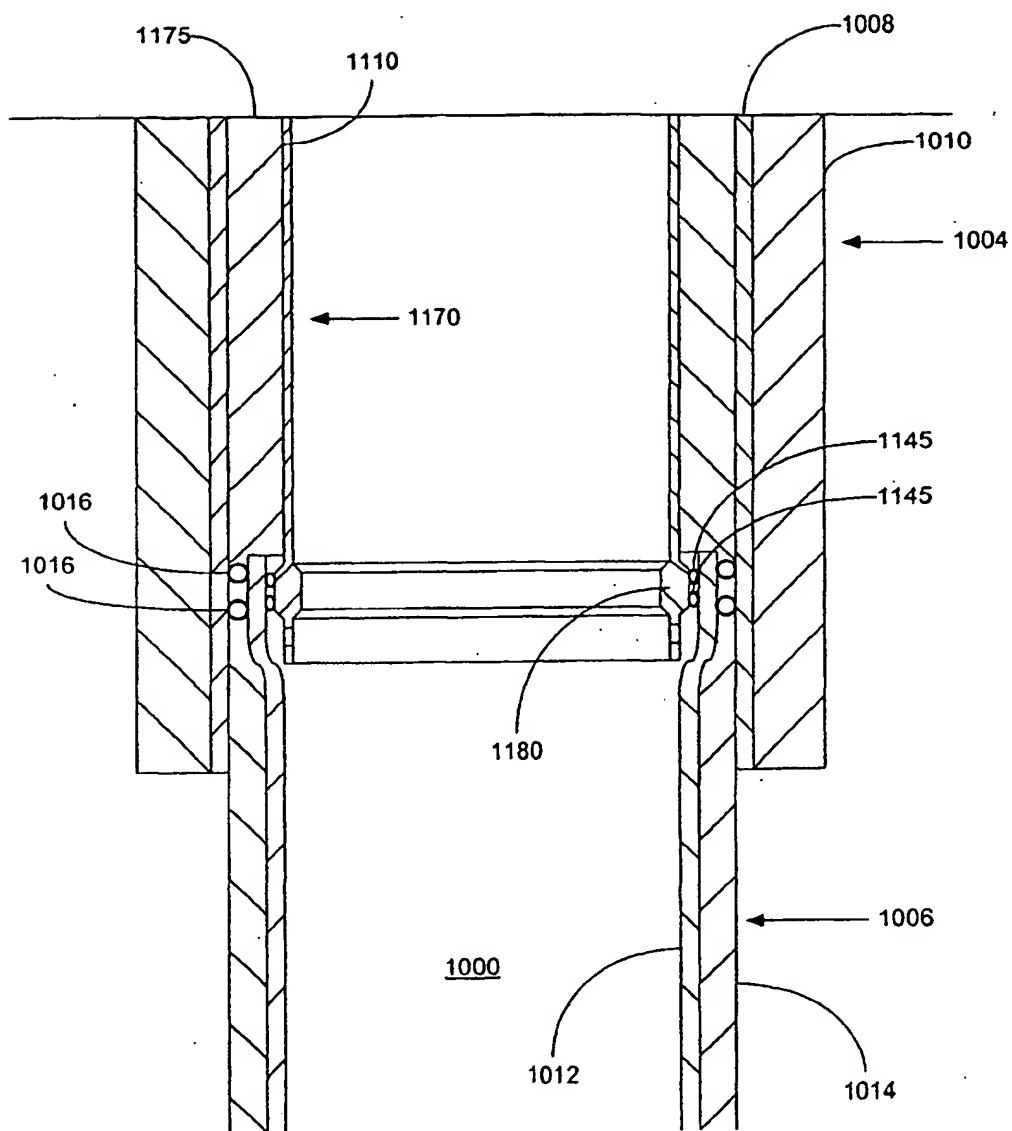


FIGURE 10g

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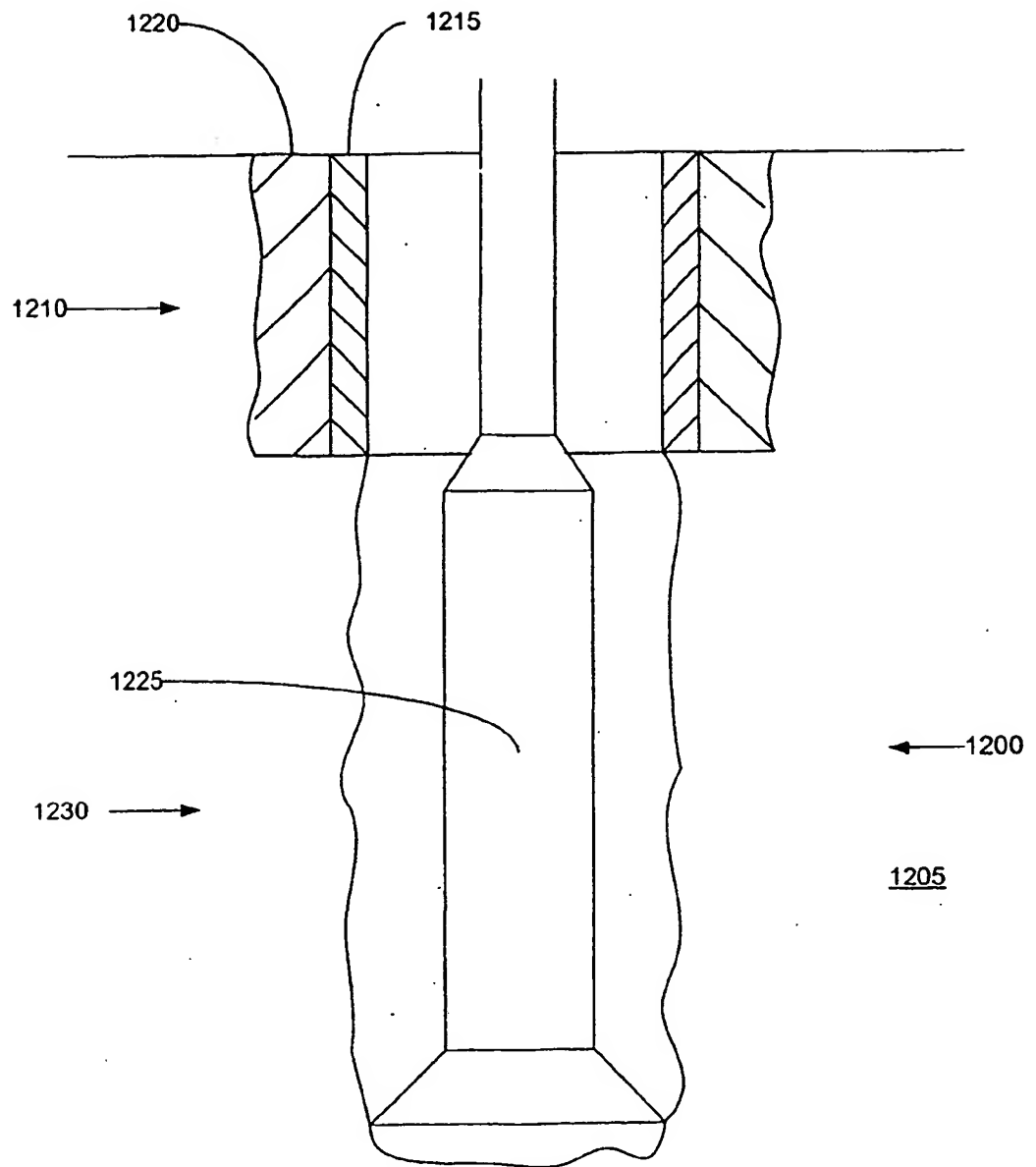


FIGURE 11a

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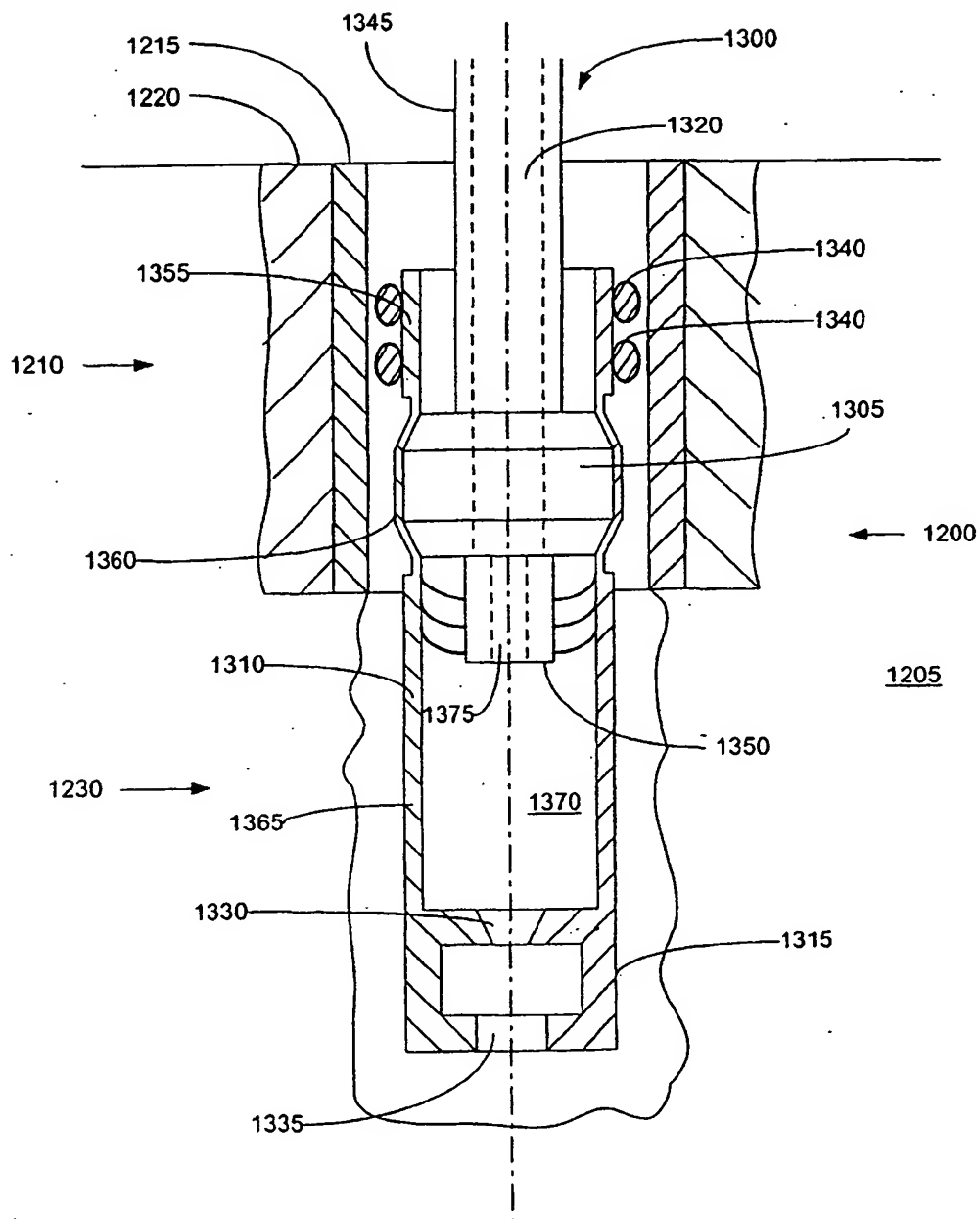


FIGURE 11b

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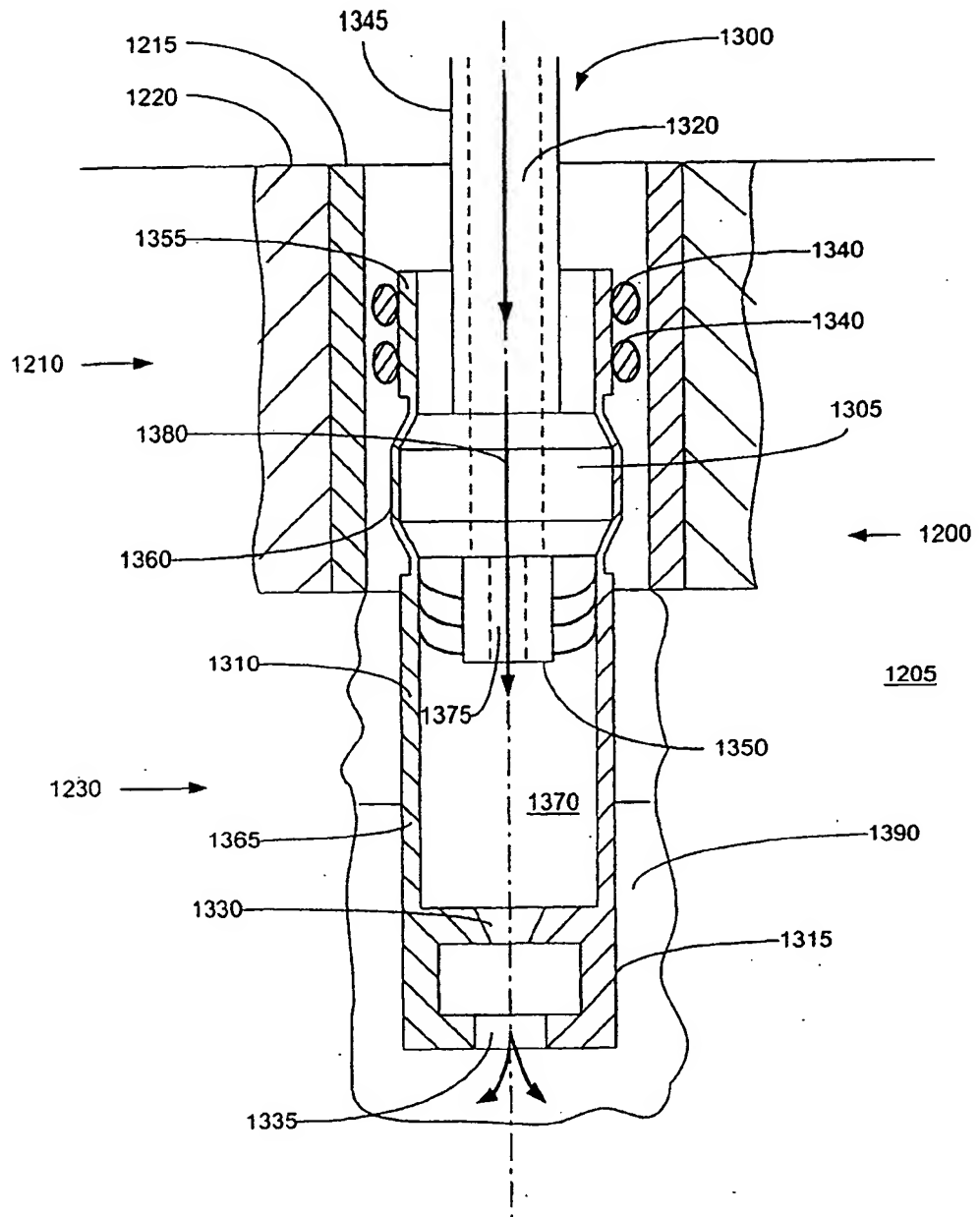


FIGURE 11c

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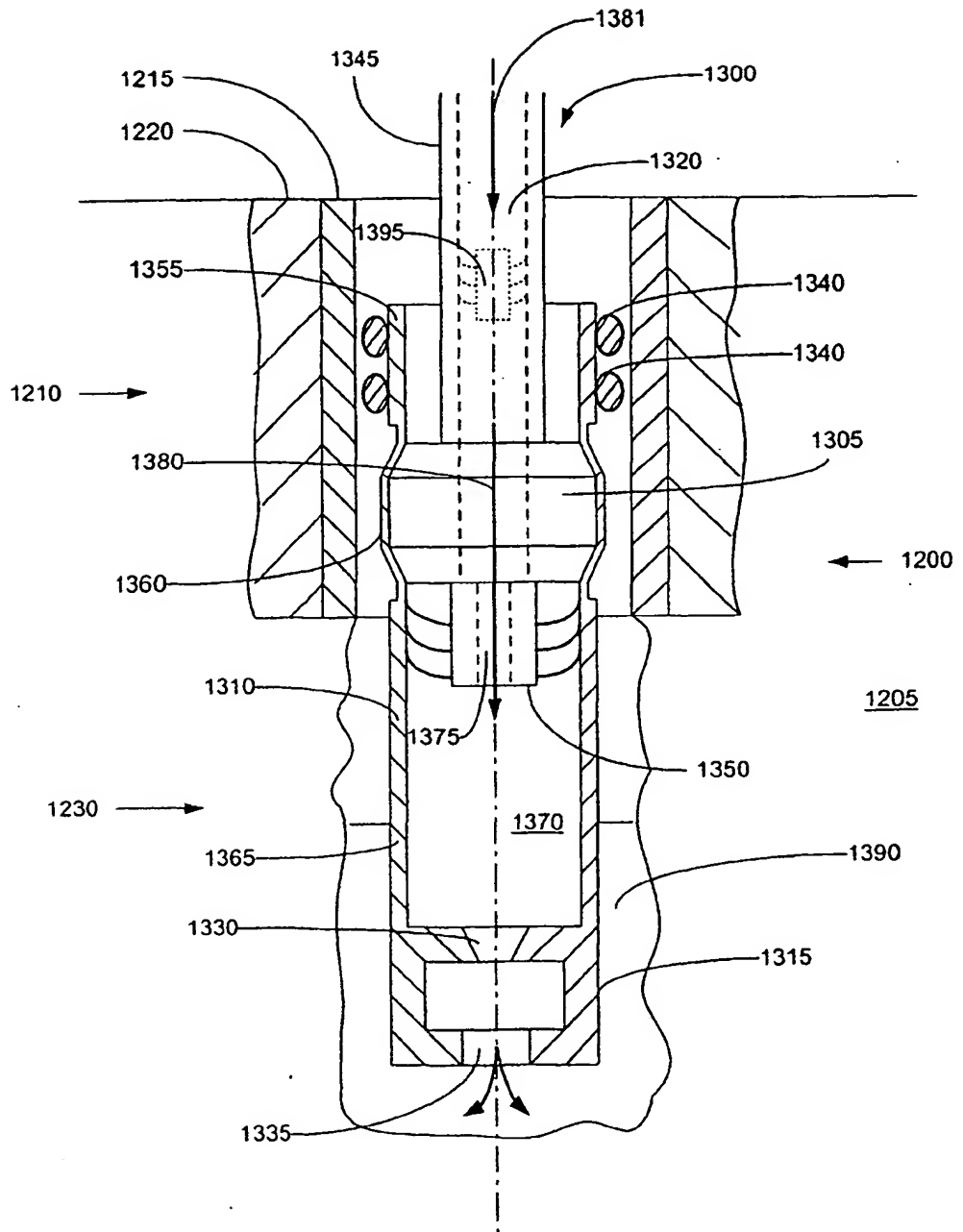


FIGURE 11d

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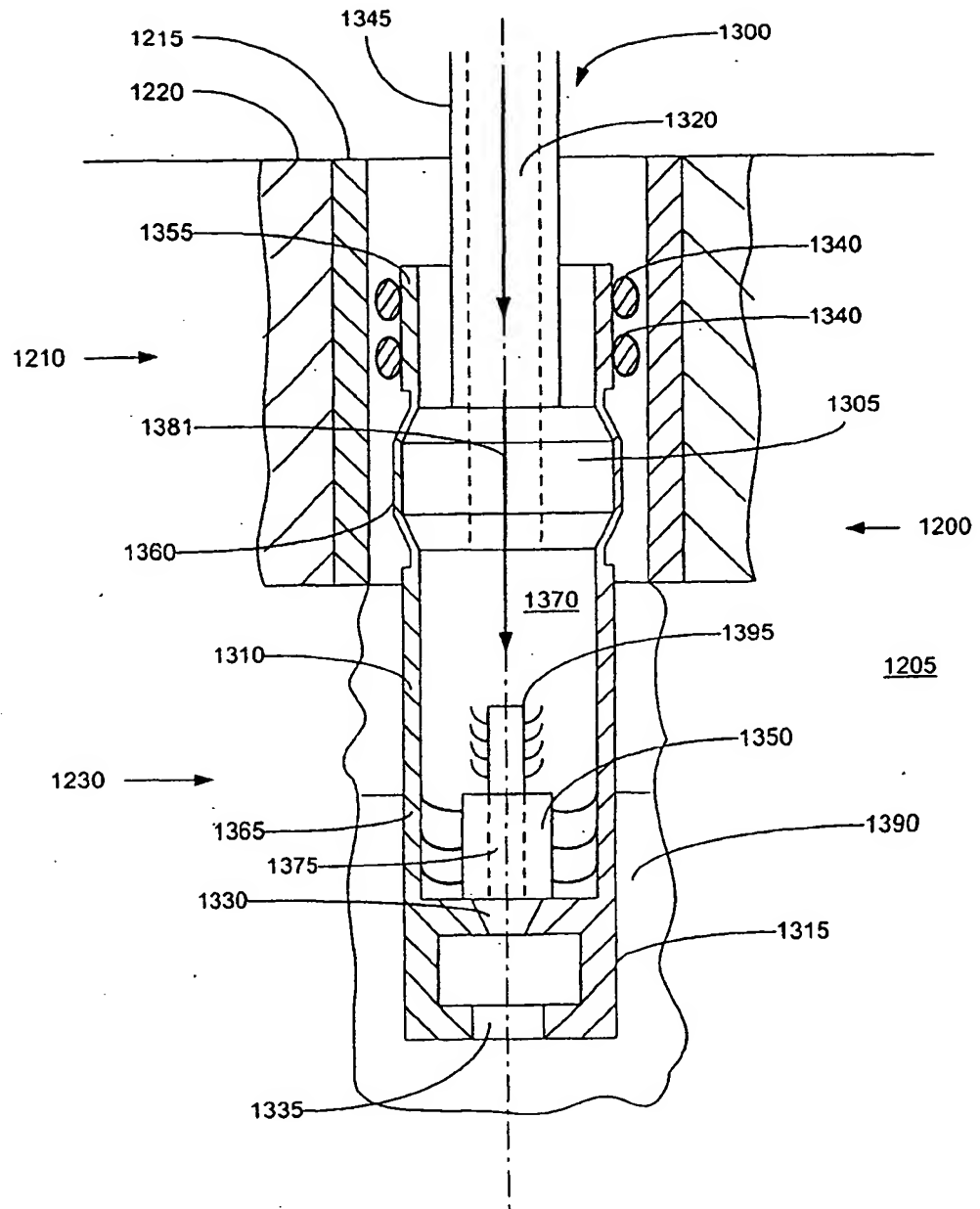


FIGURE 11e

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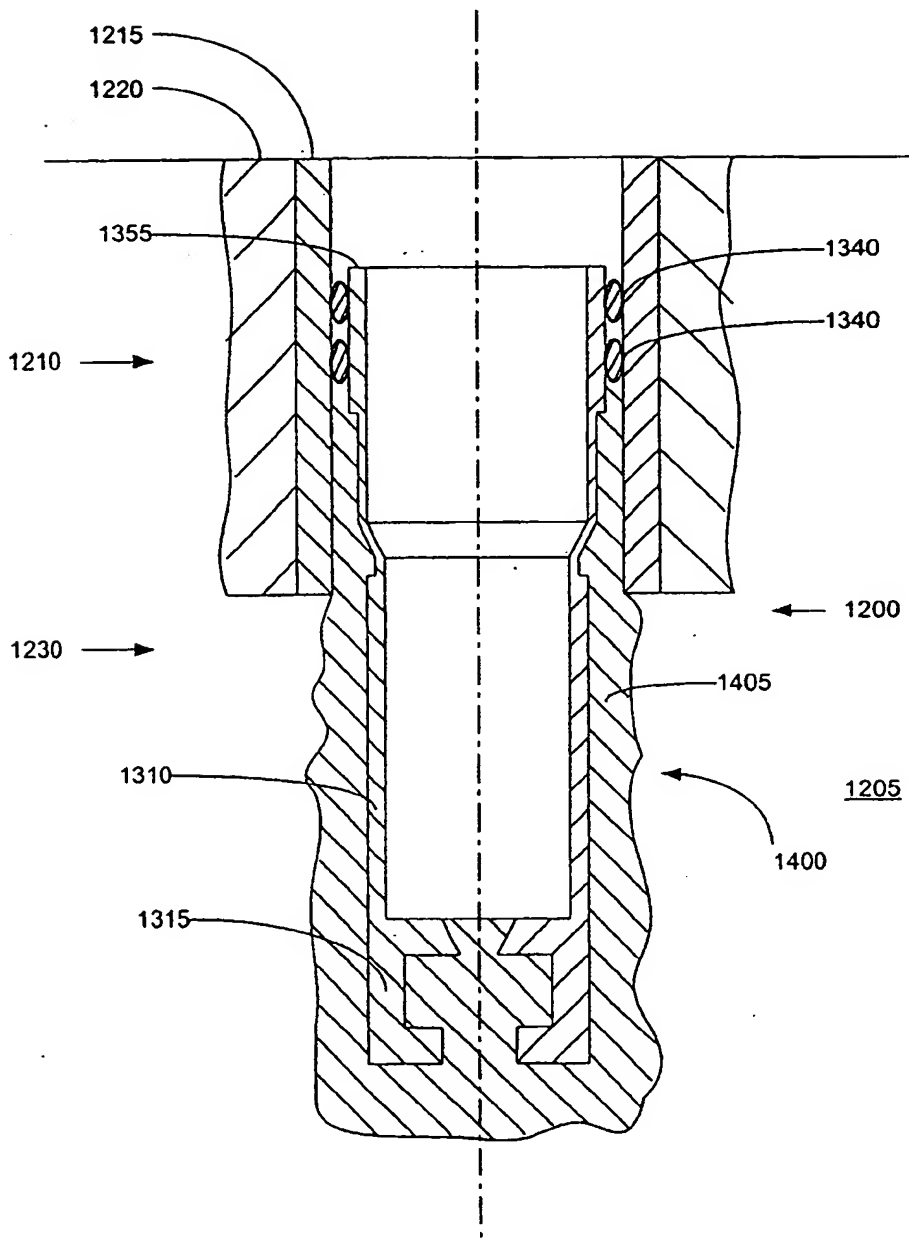


FIGURE 11f

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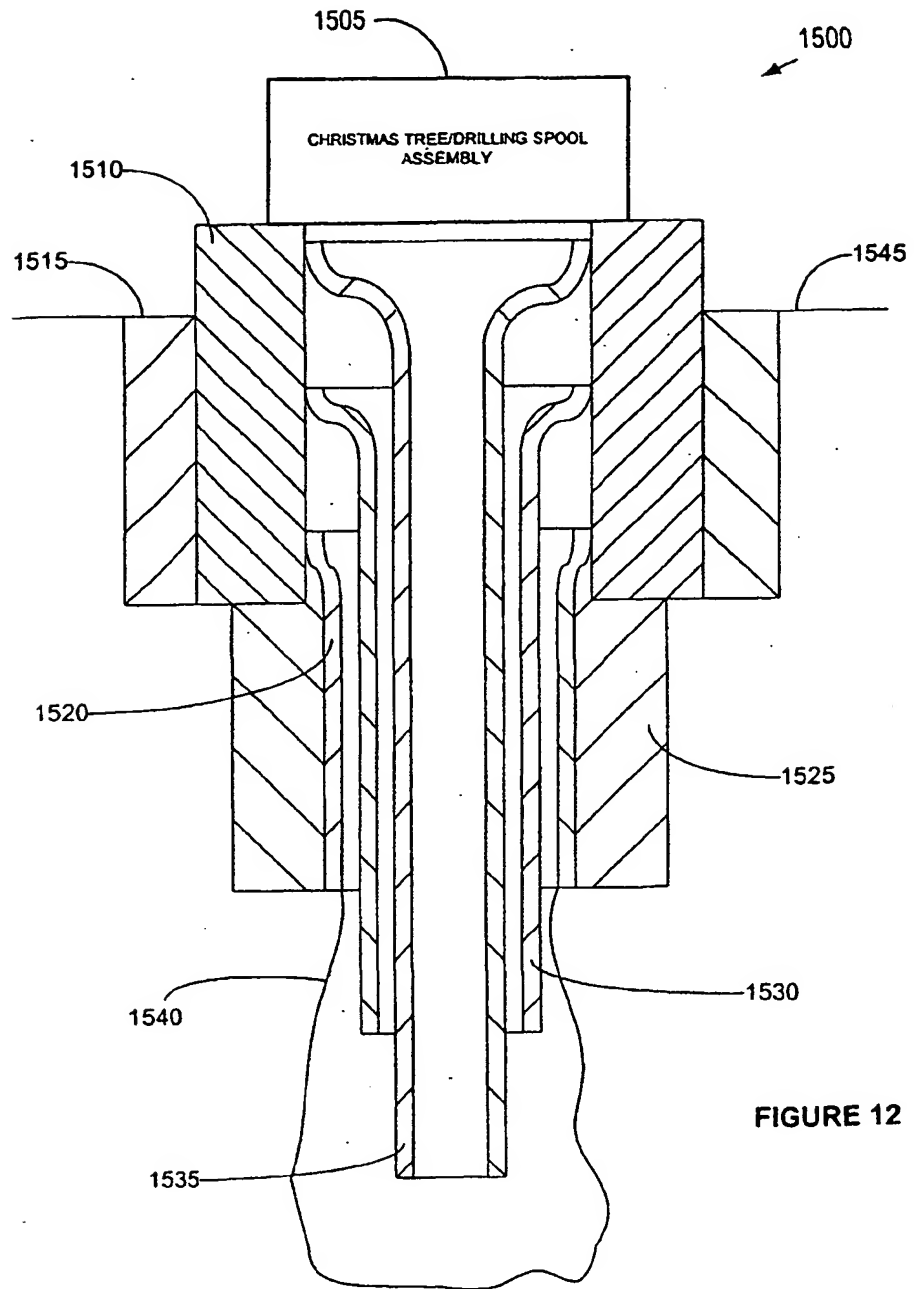


FIGURE 12

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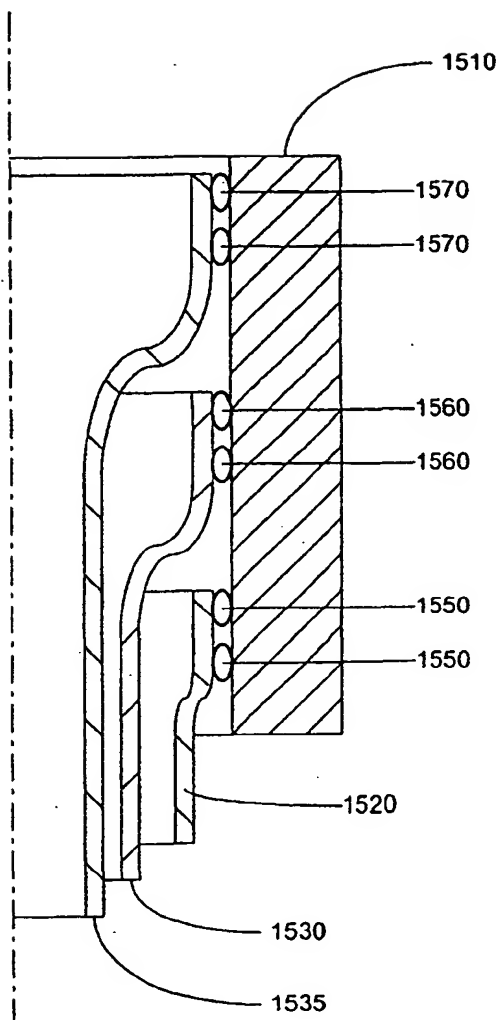


FIGURE 13

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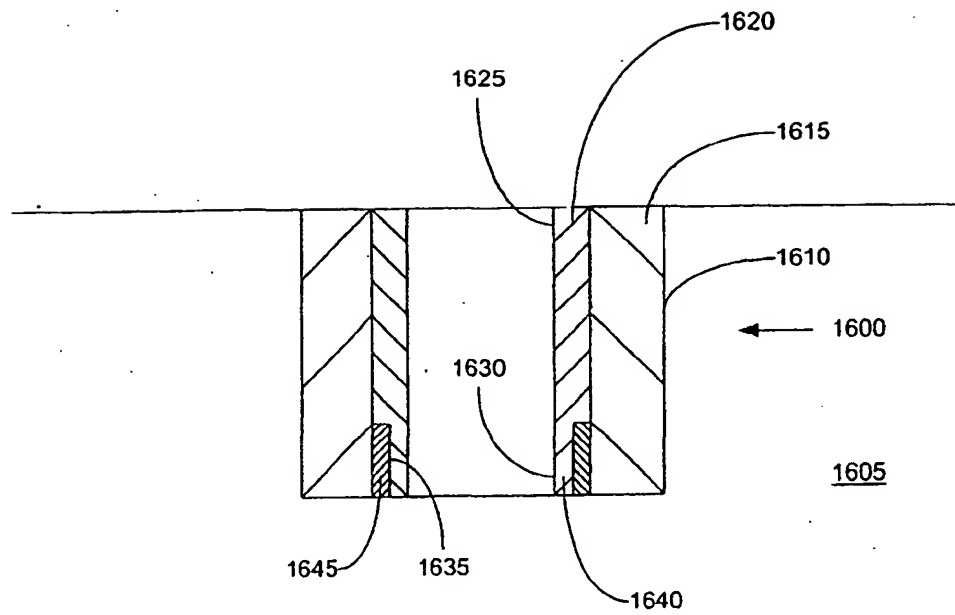


FIGURE 14a

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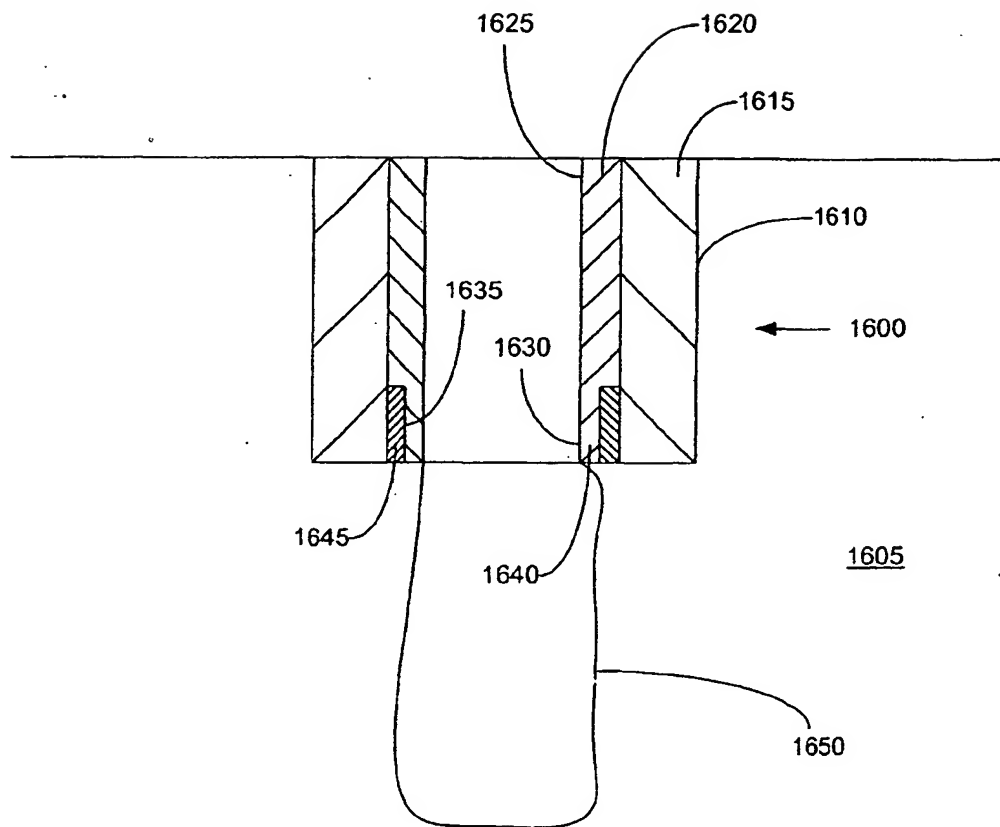


FIGURE 14b

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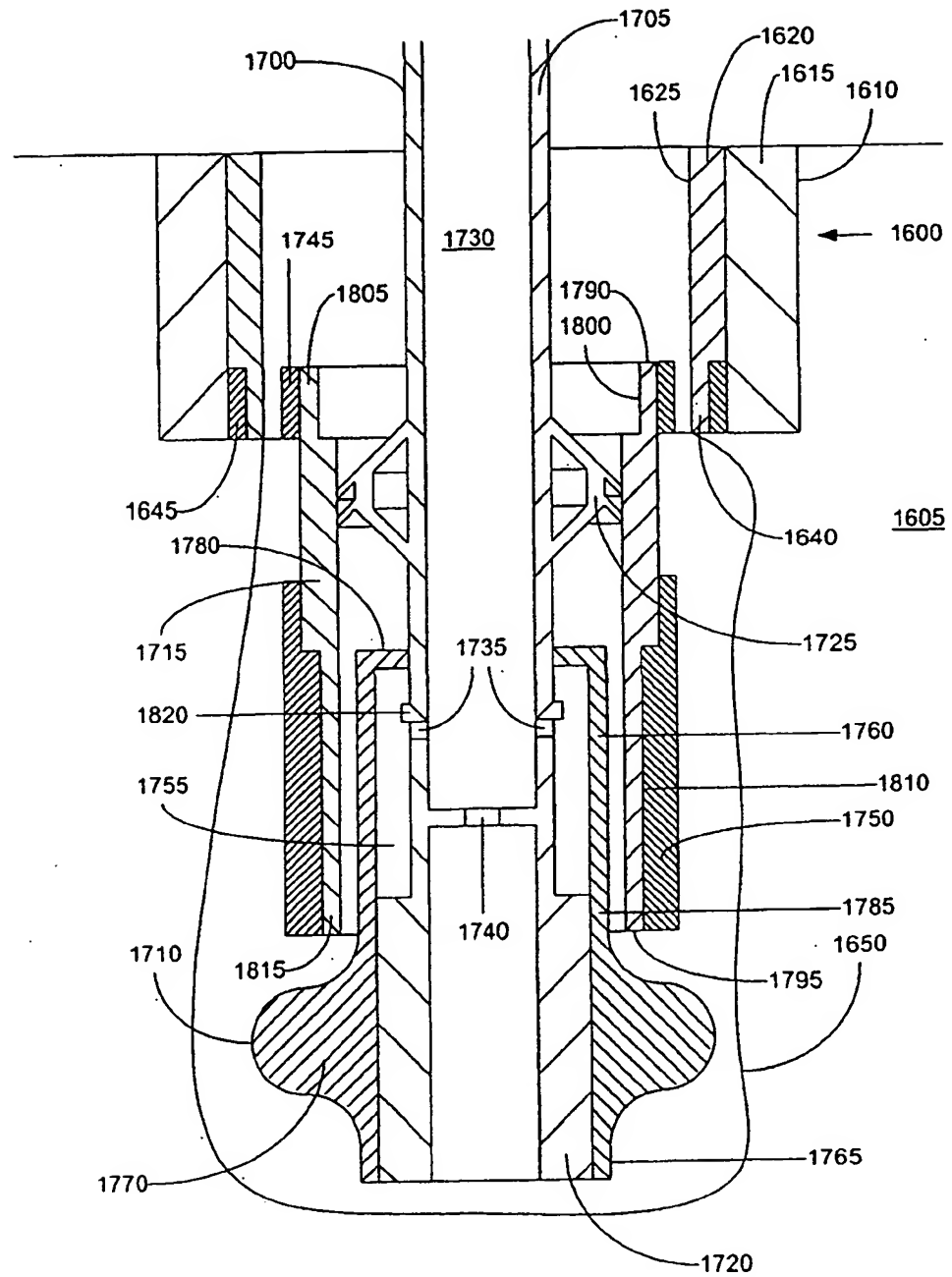


FIGURE 14c

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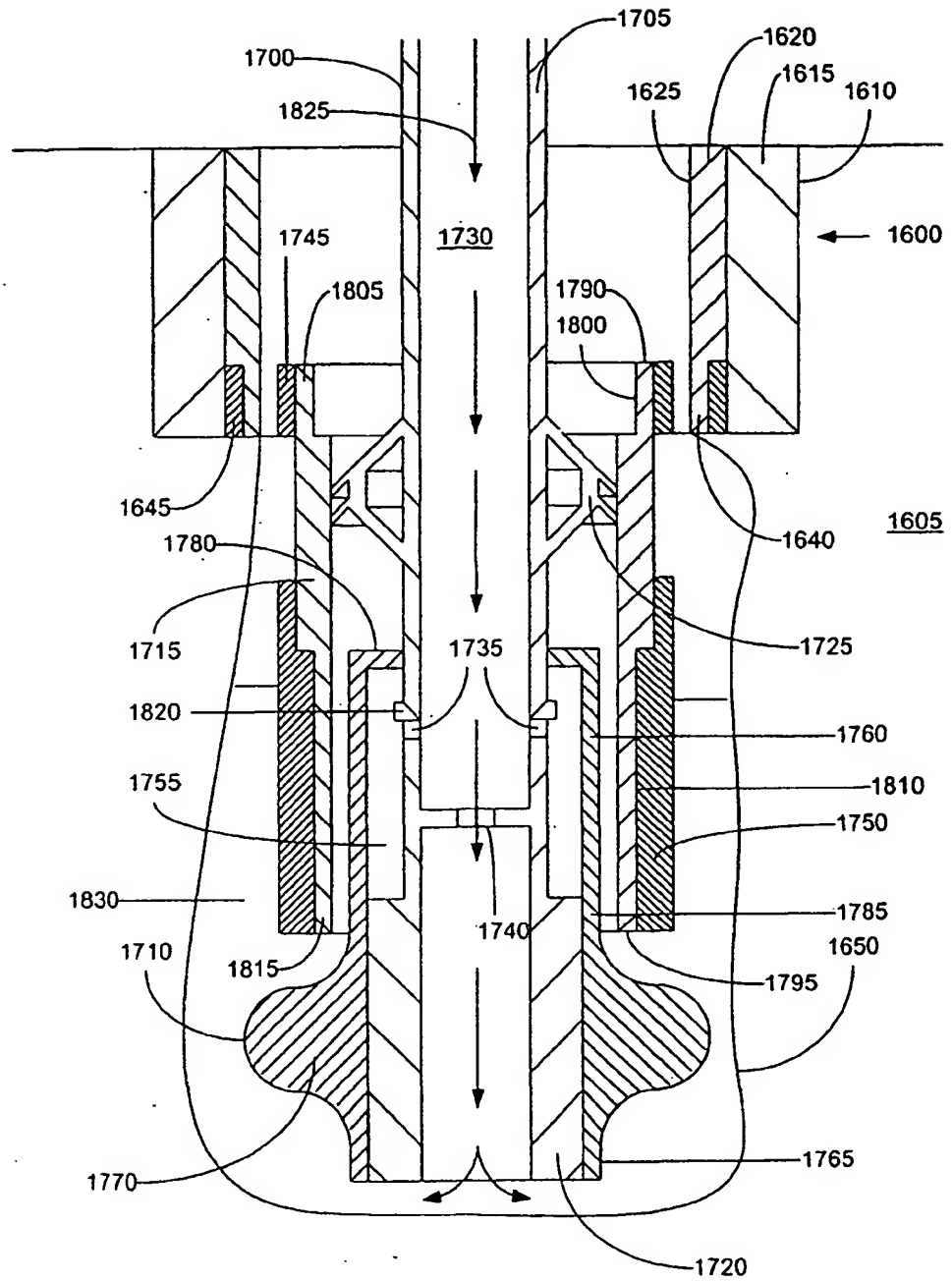


FIGURE 14d

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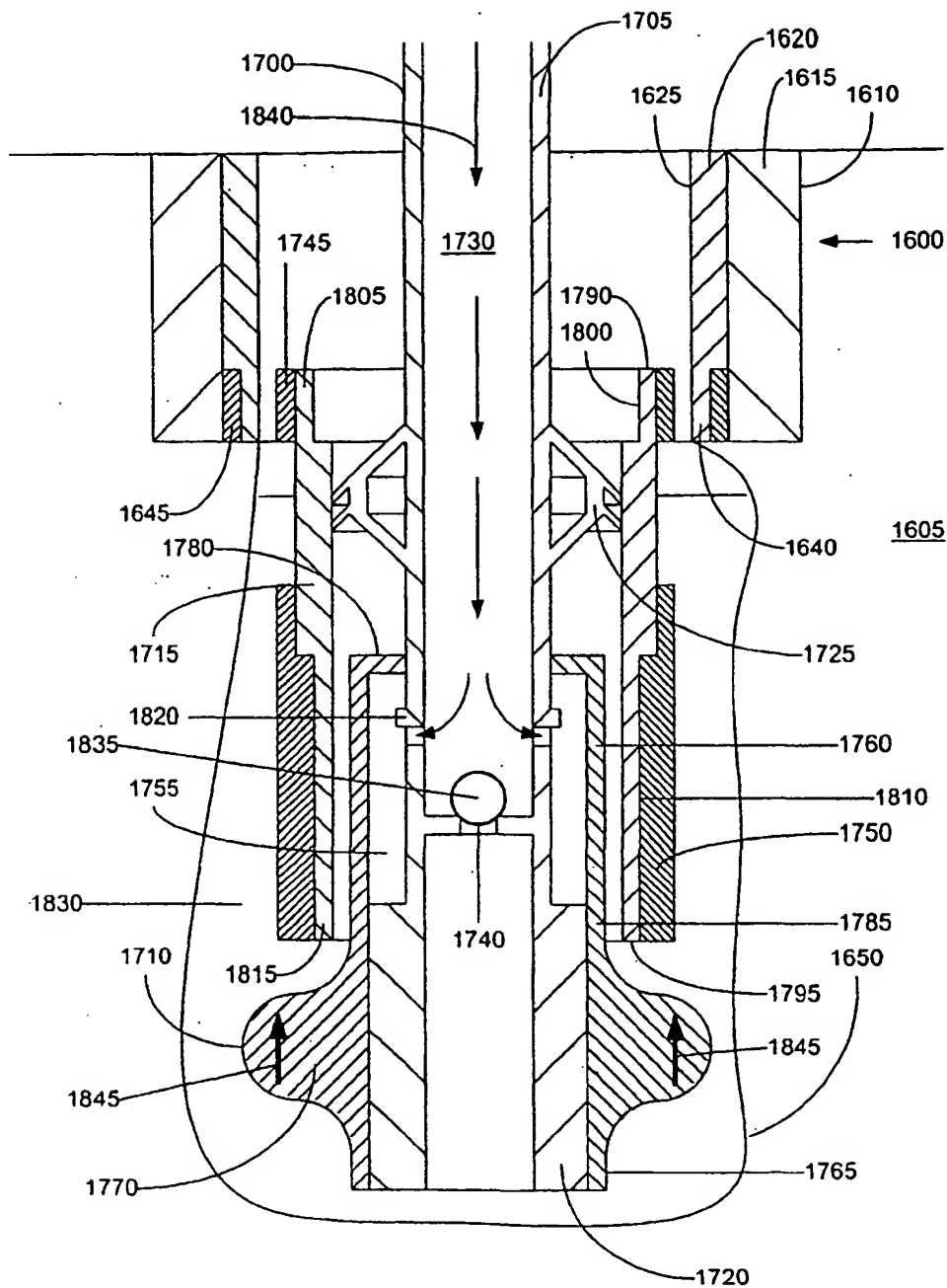


FIGURE 14e

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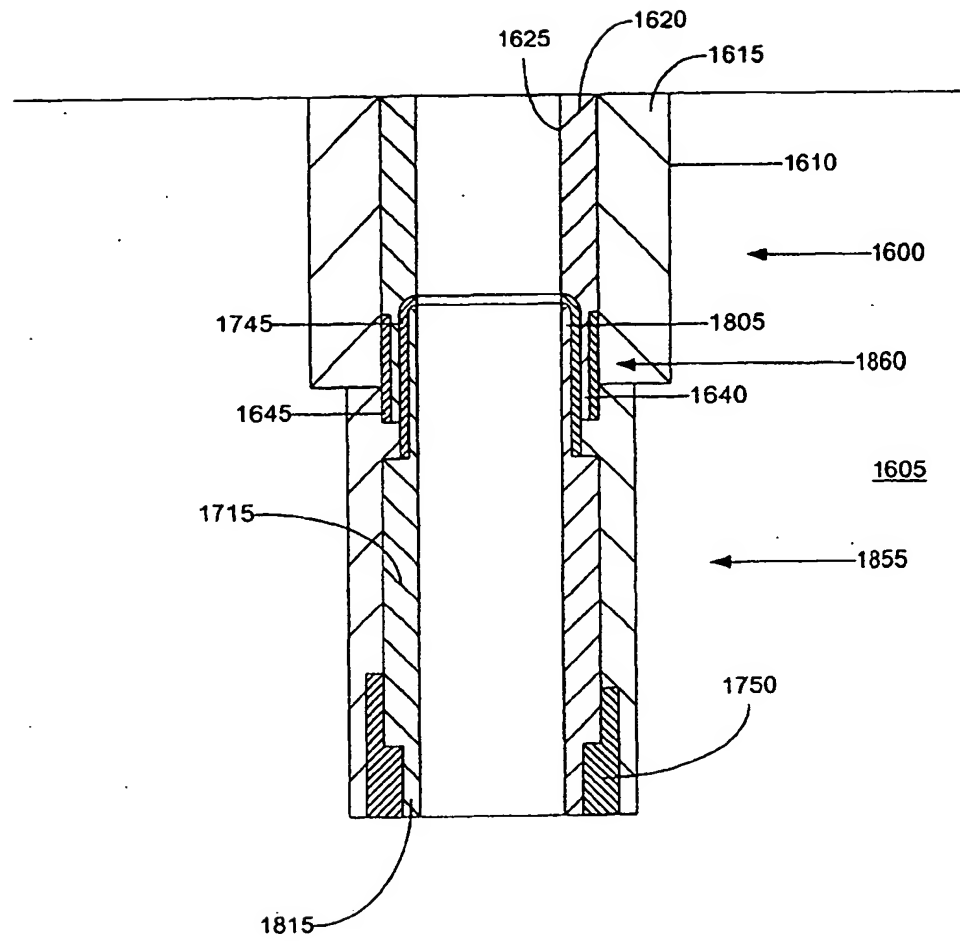


FIGURE 14f

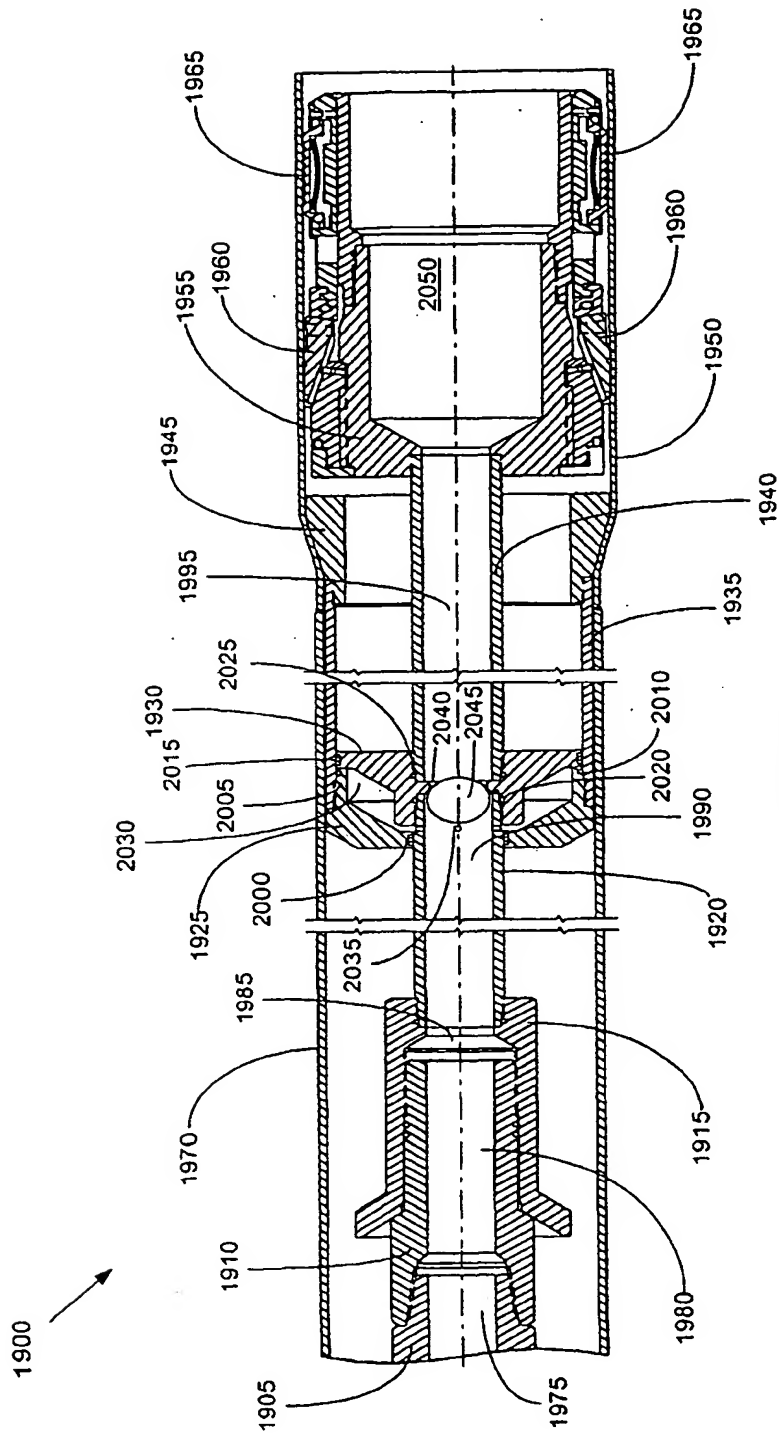


FIGURE 15

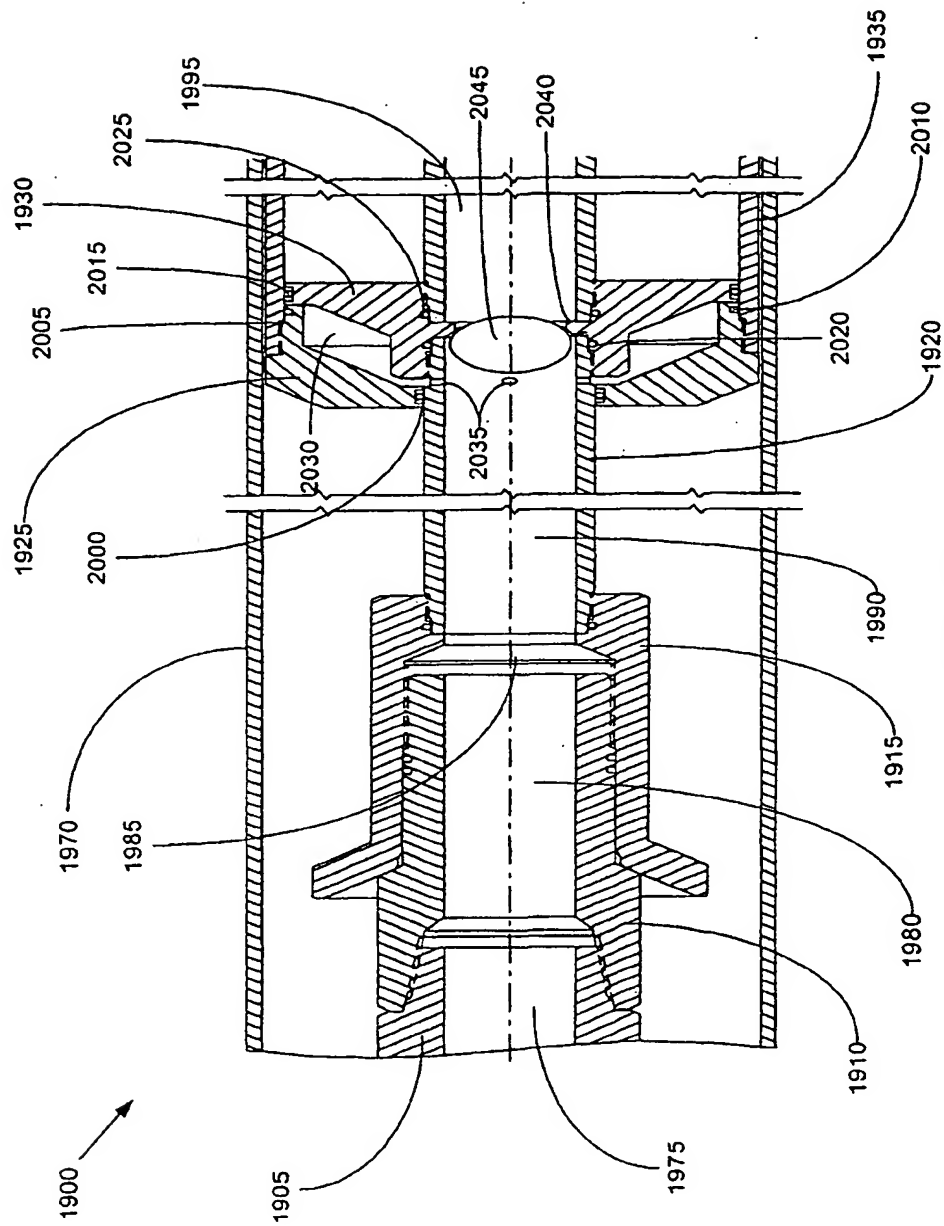


FIGURE 15a

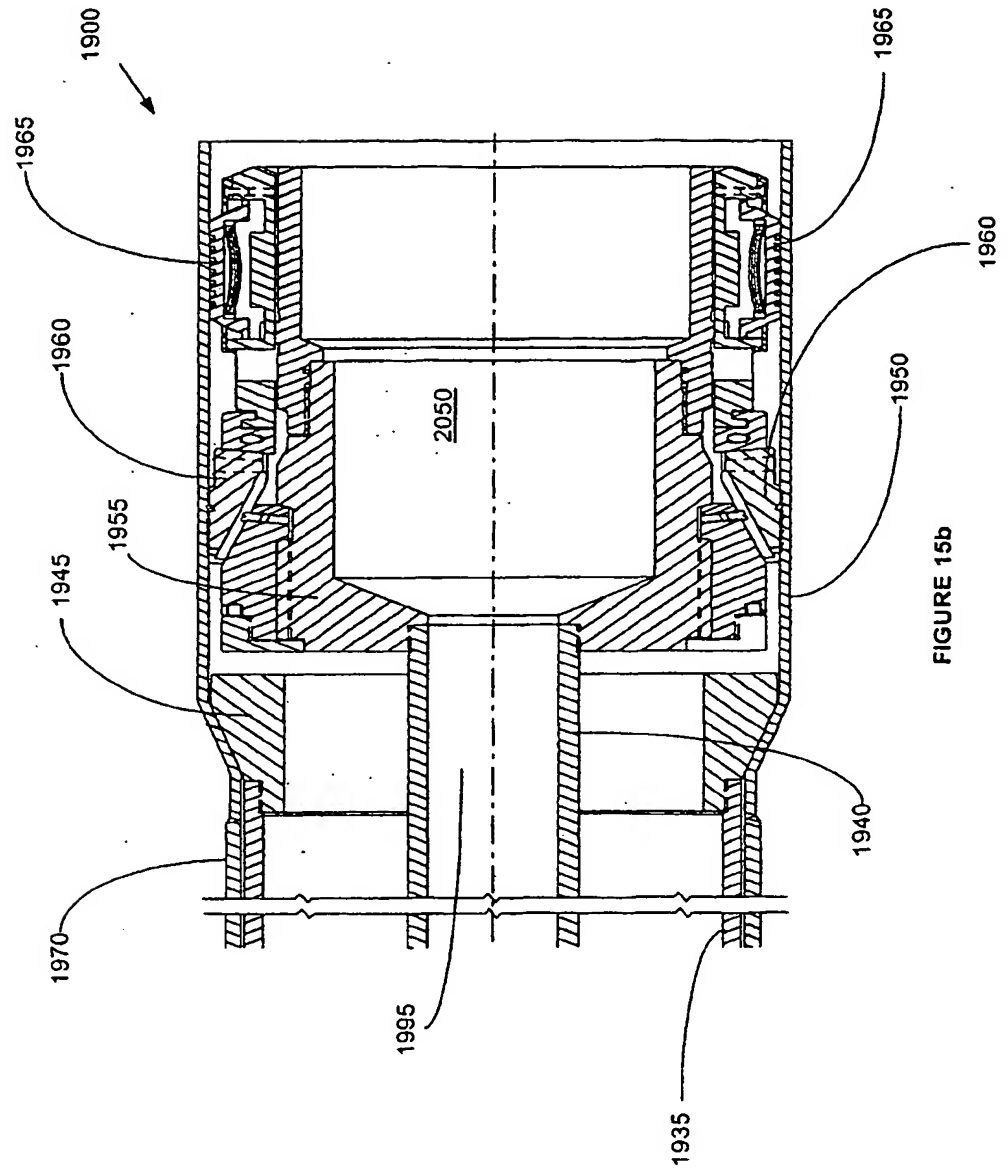


FIGURE 15b

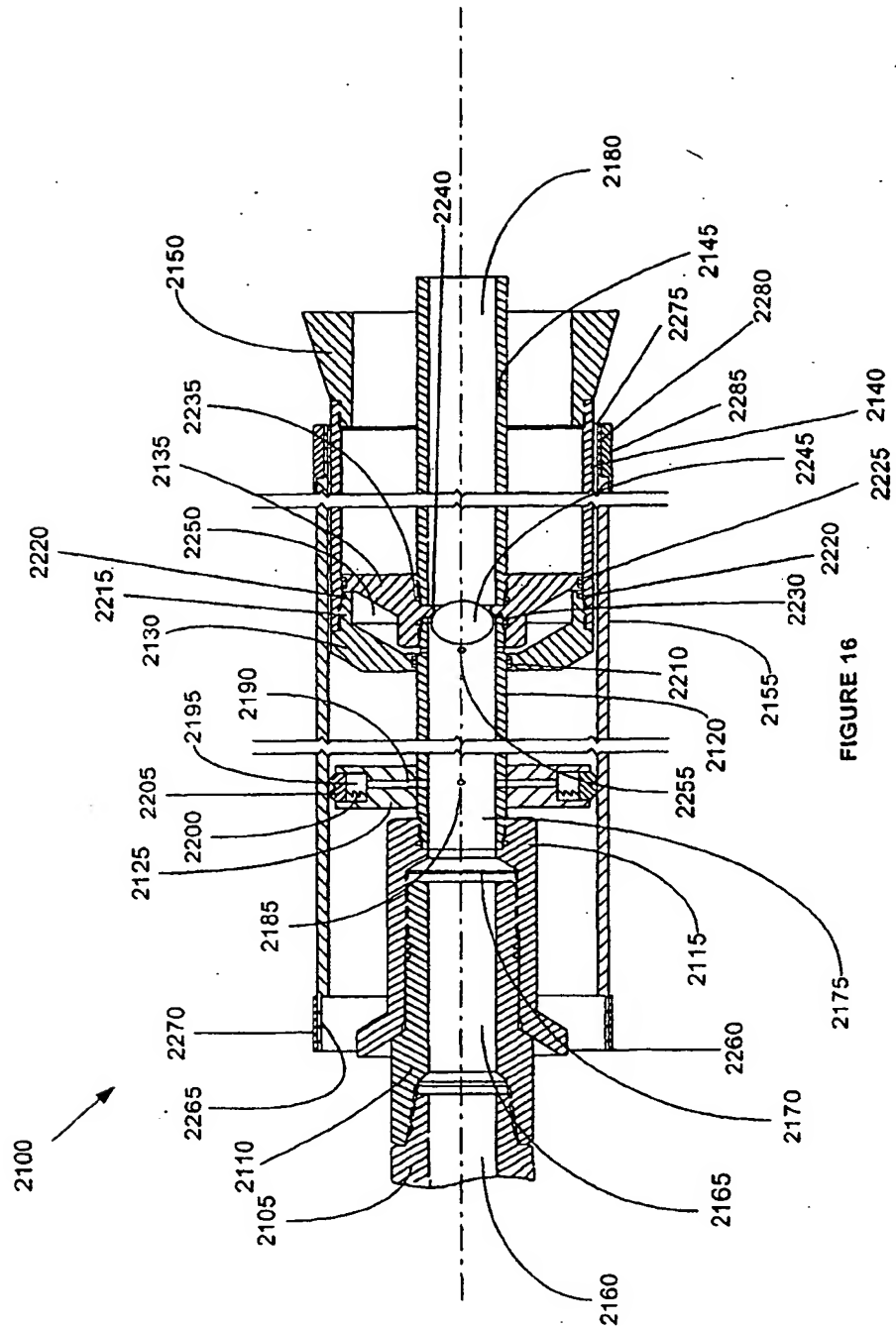


FIGURE 16

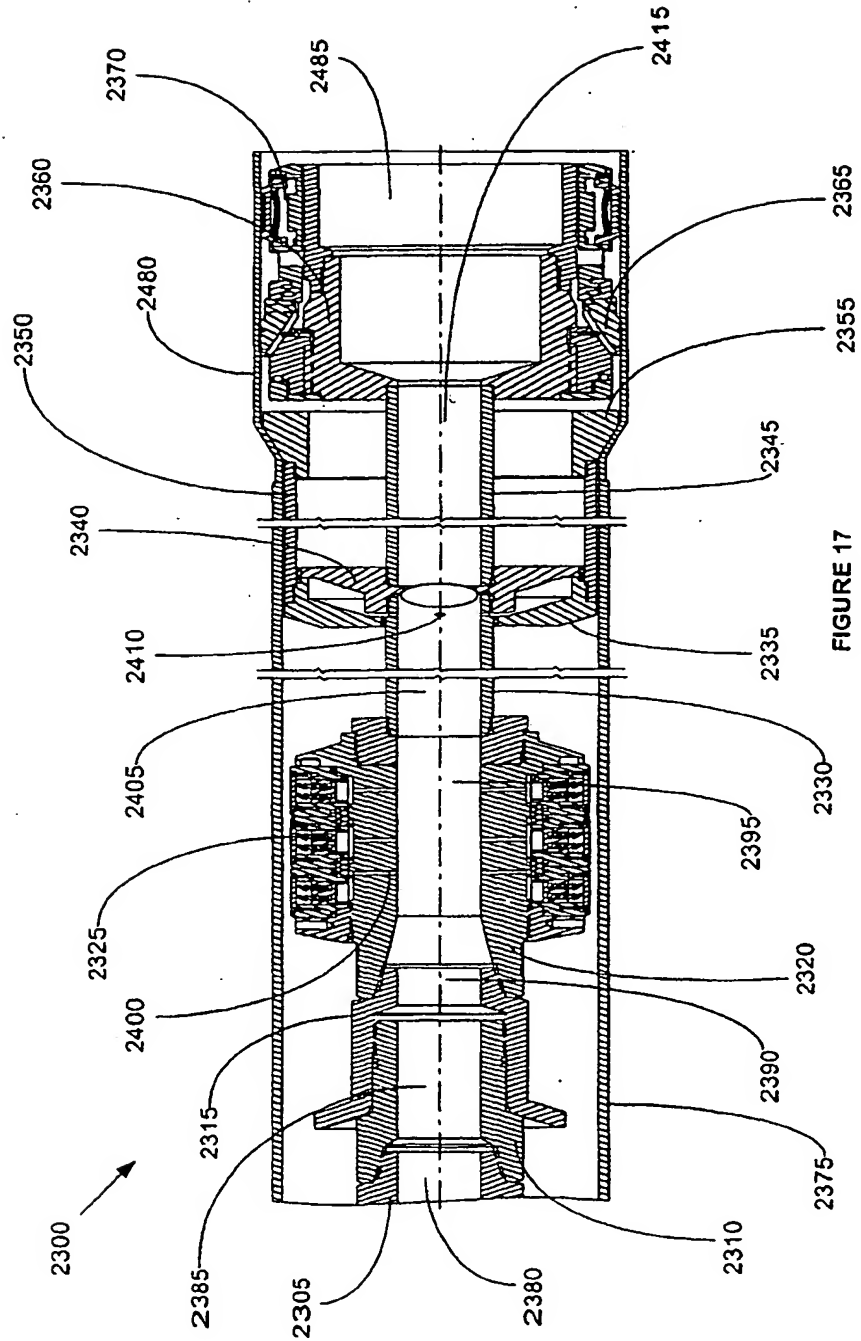


FIGURE 17

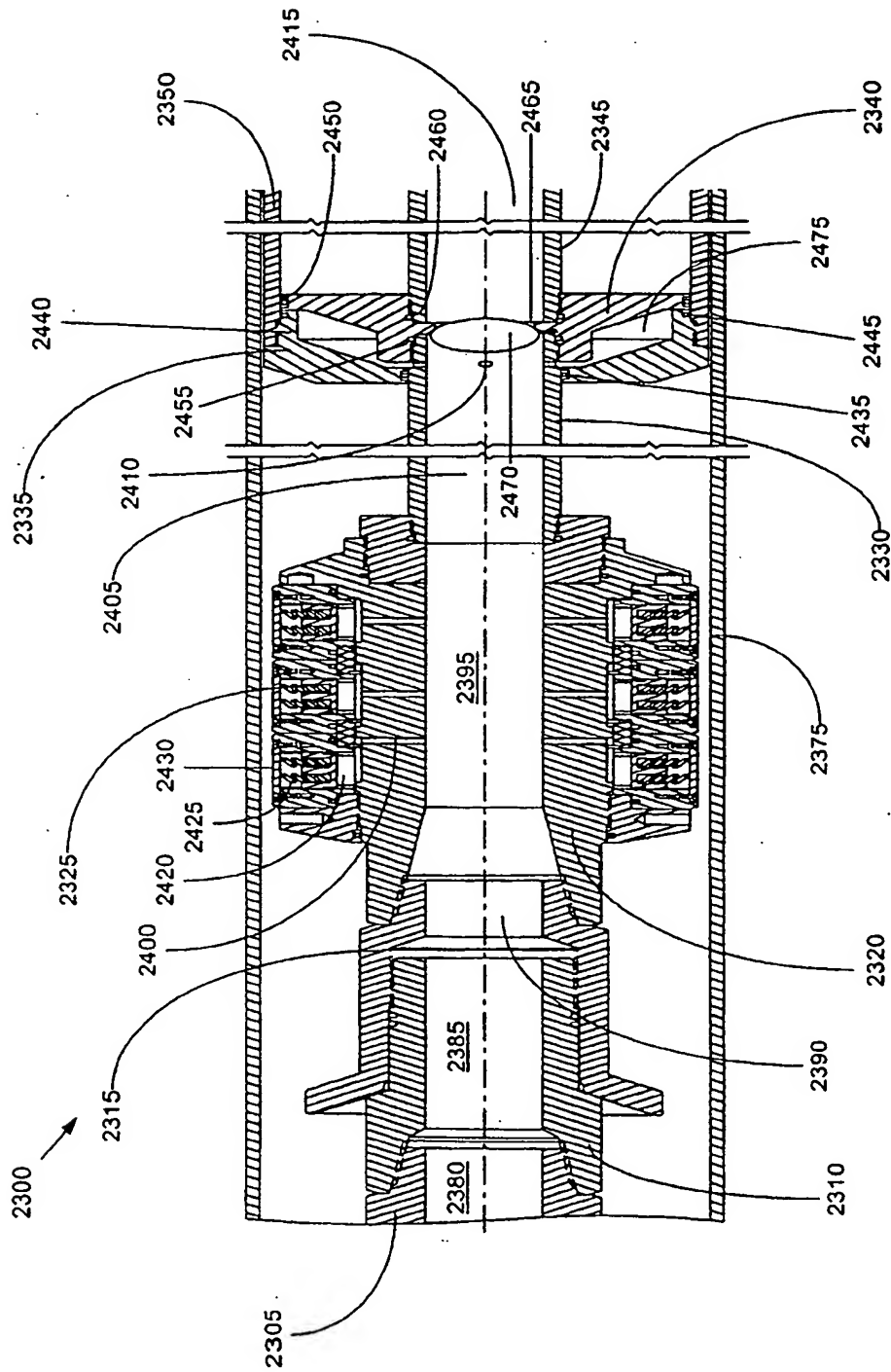


FIGURE 17a

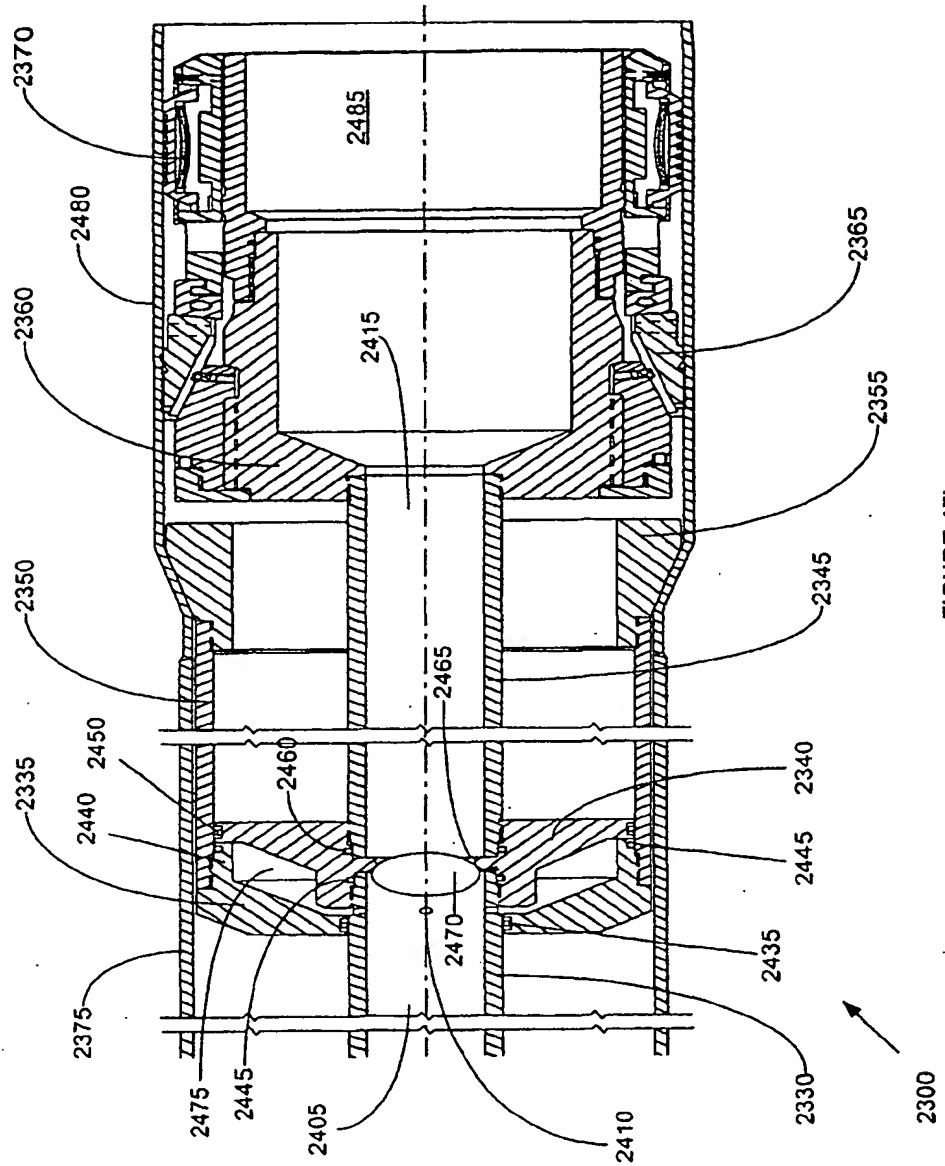


FIGURE 17b

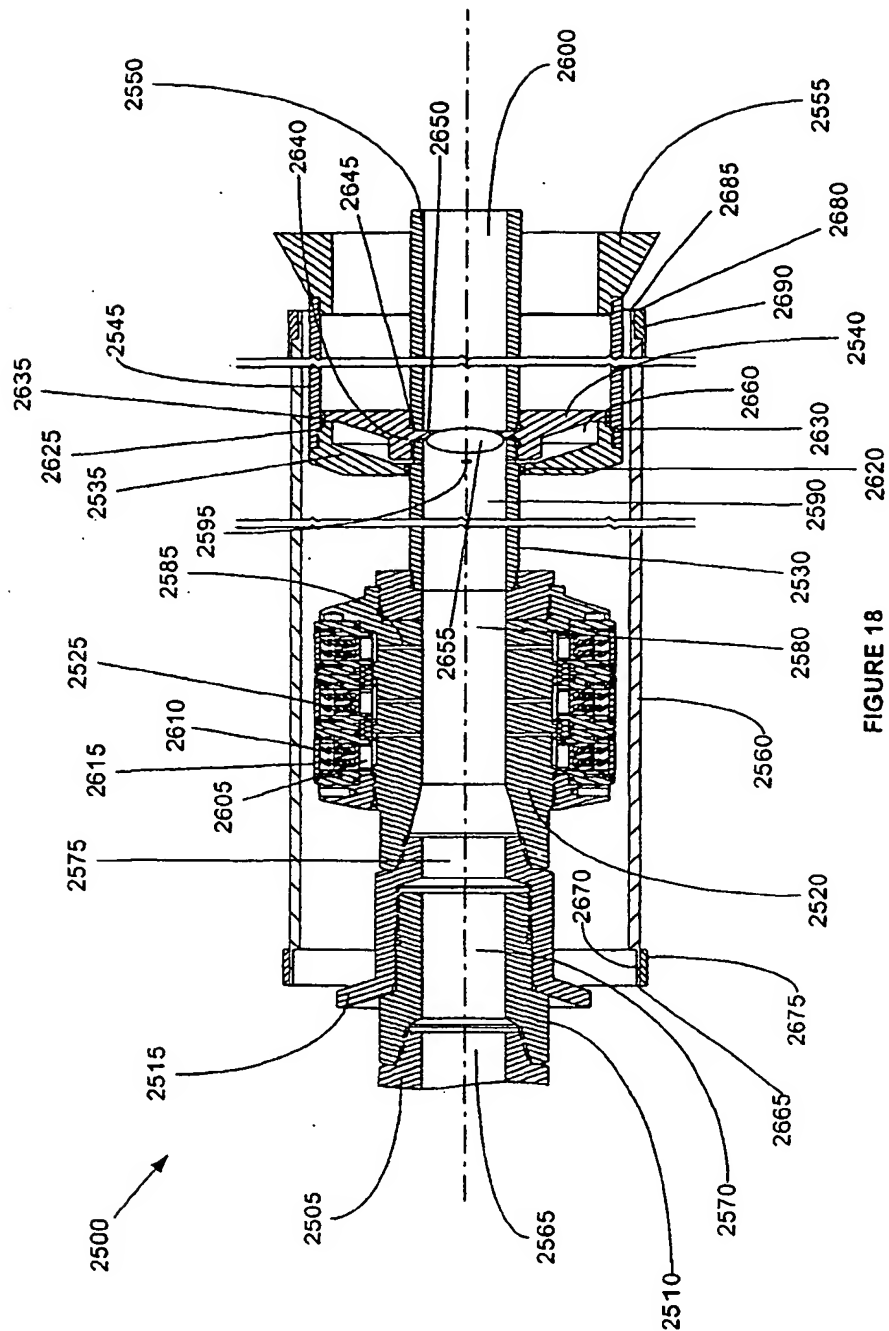


FIGURE 18

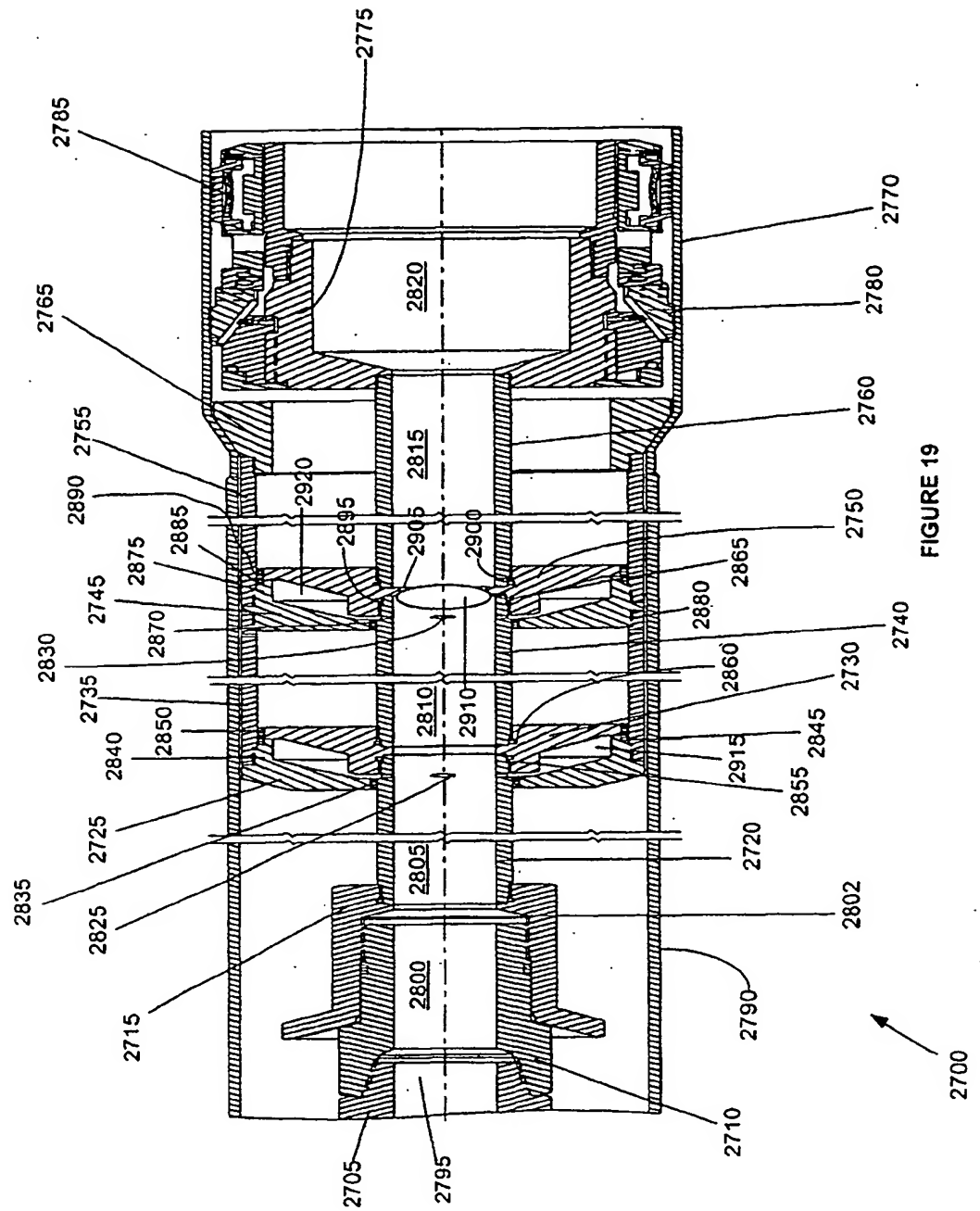
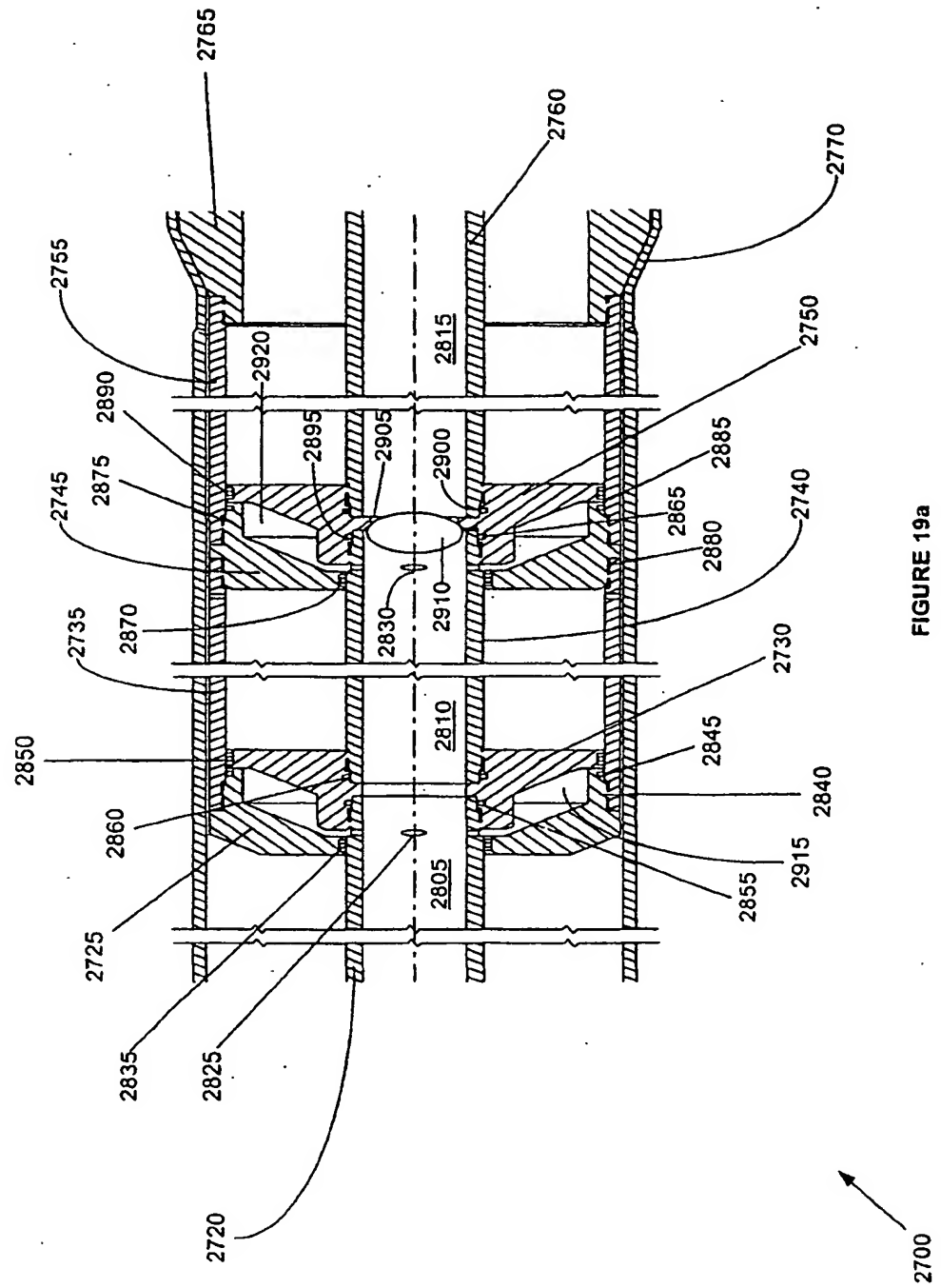


FIGURE 19



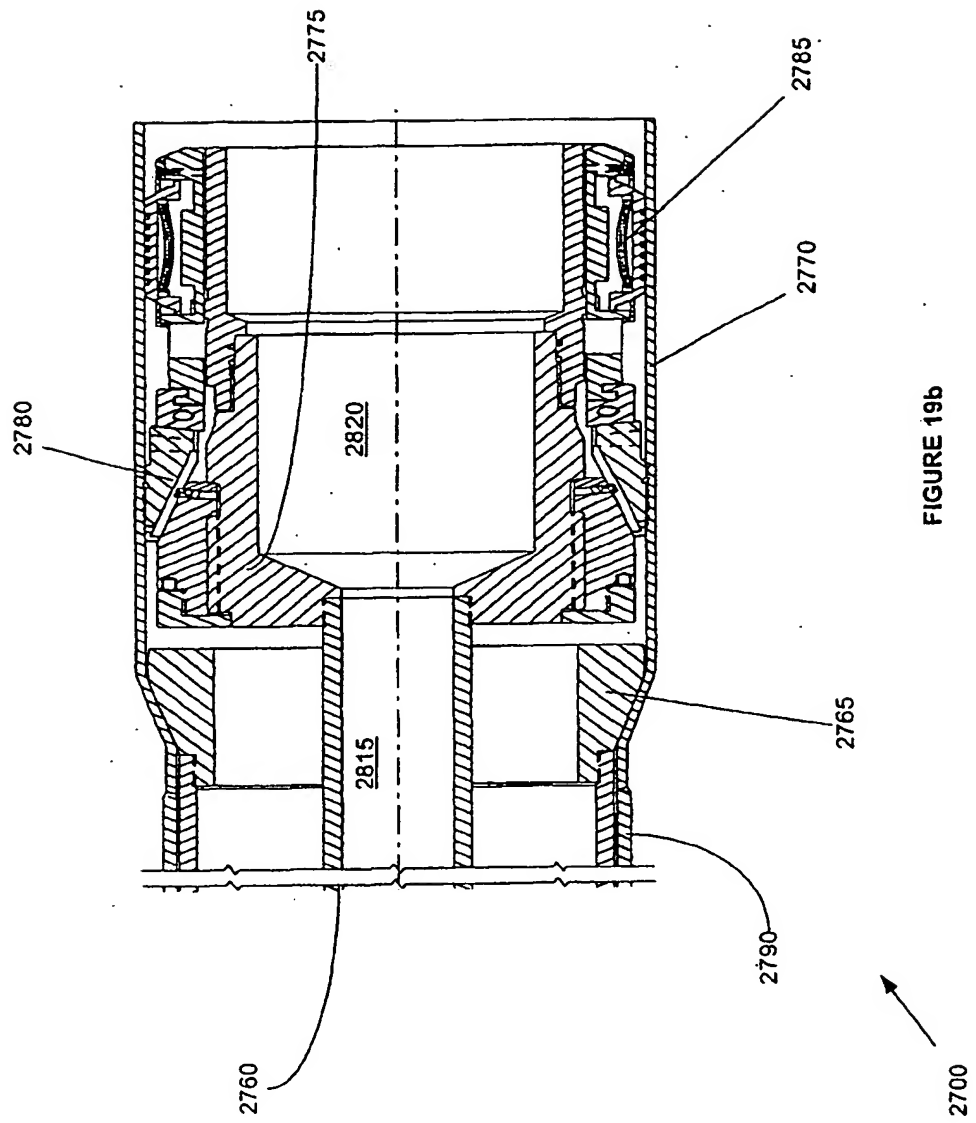
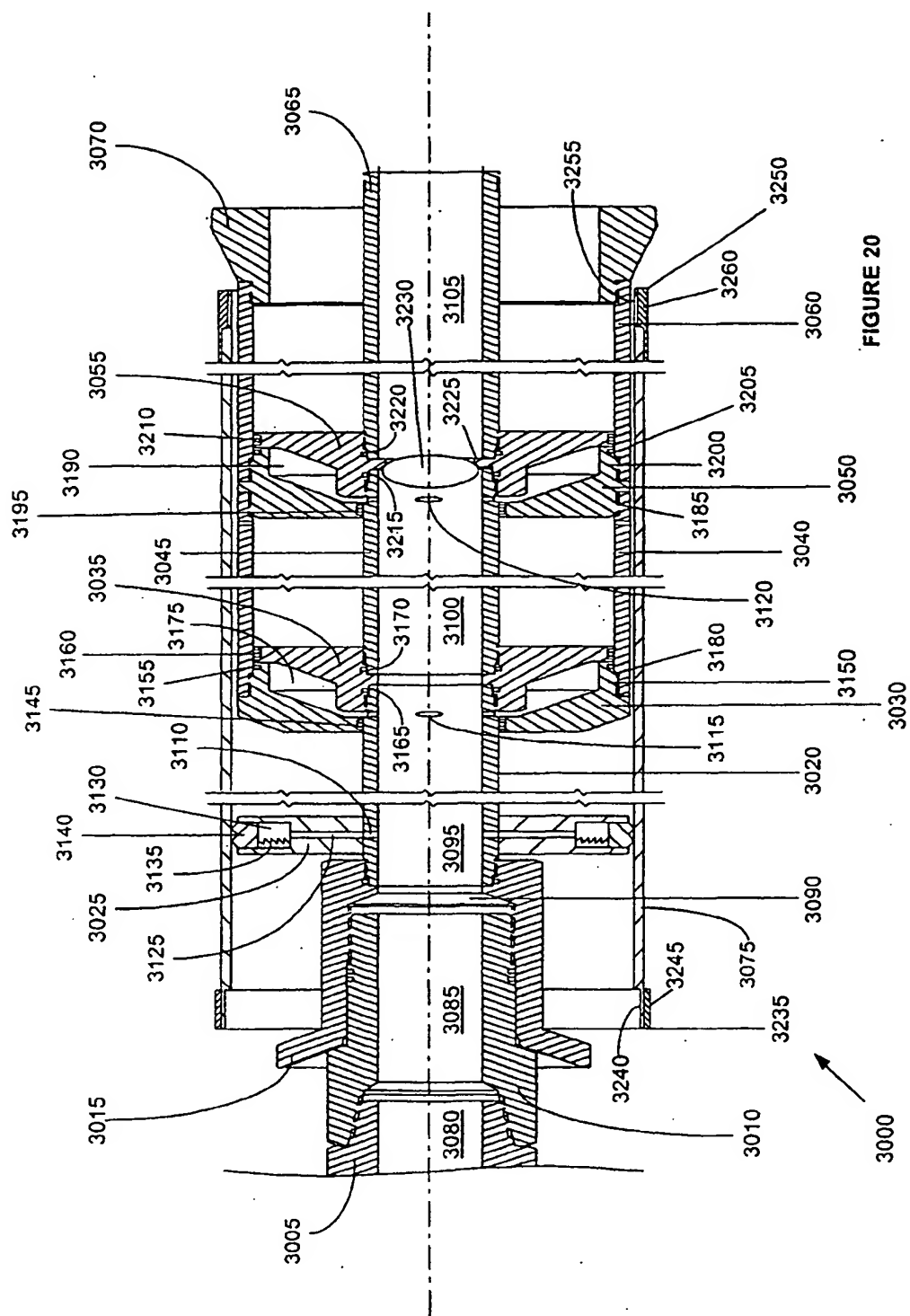


FIGURE 19b



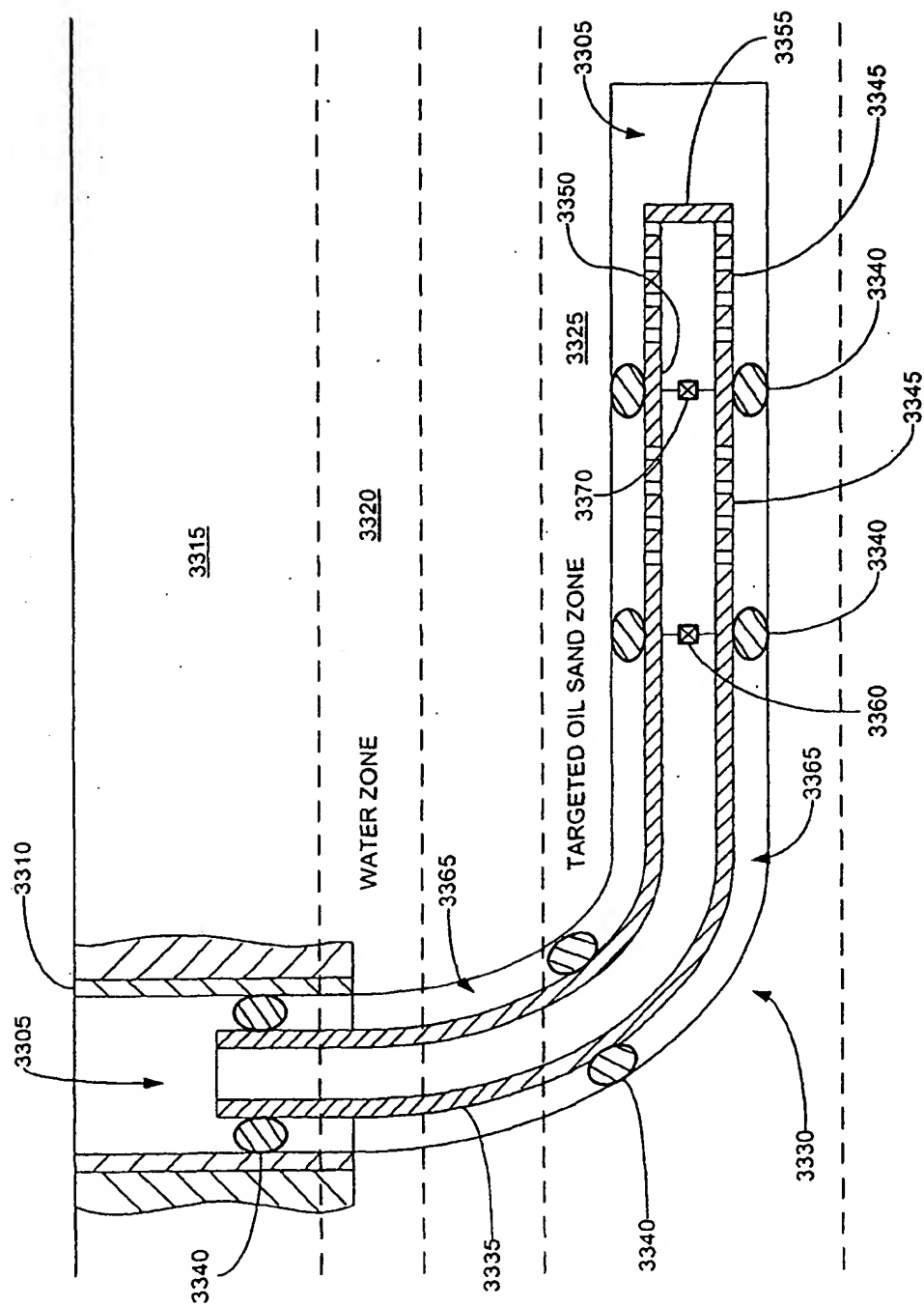


FIGURE 21

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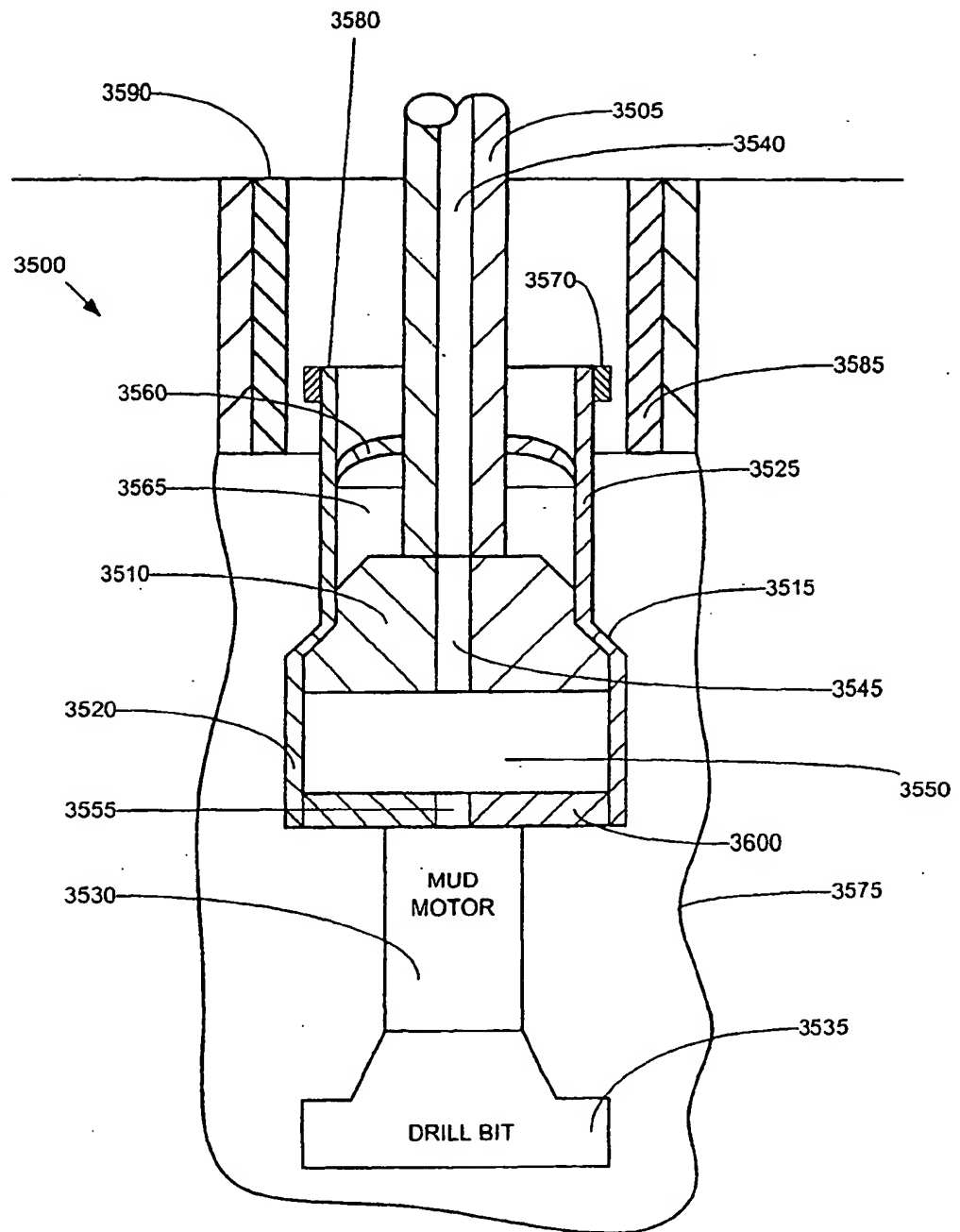


FIGURE 22A

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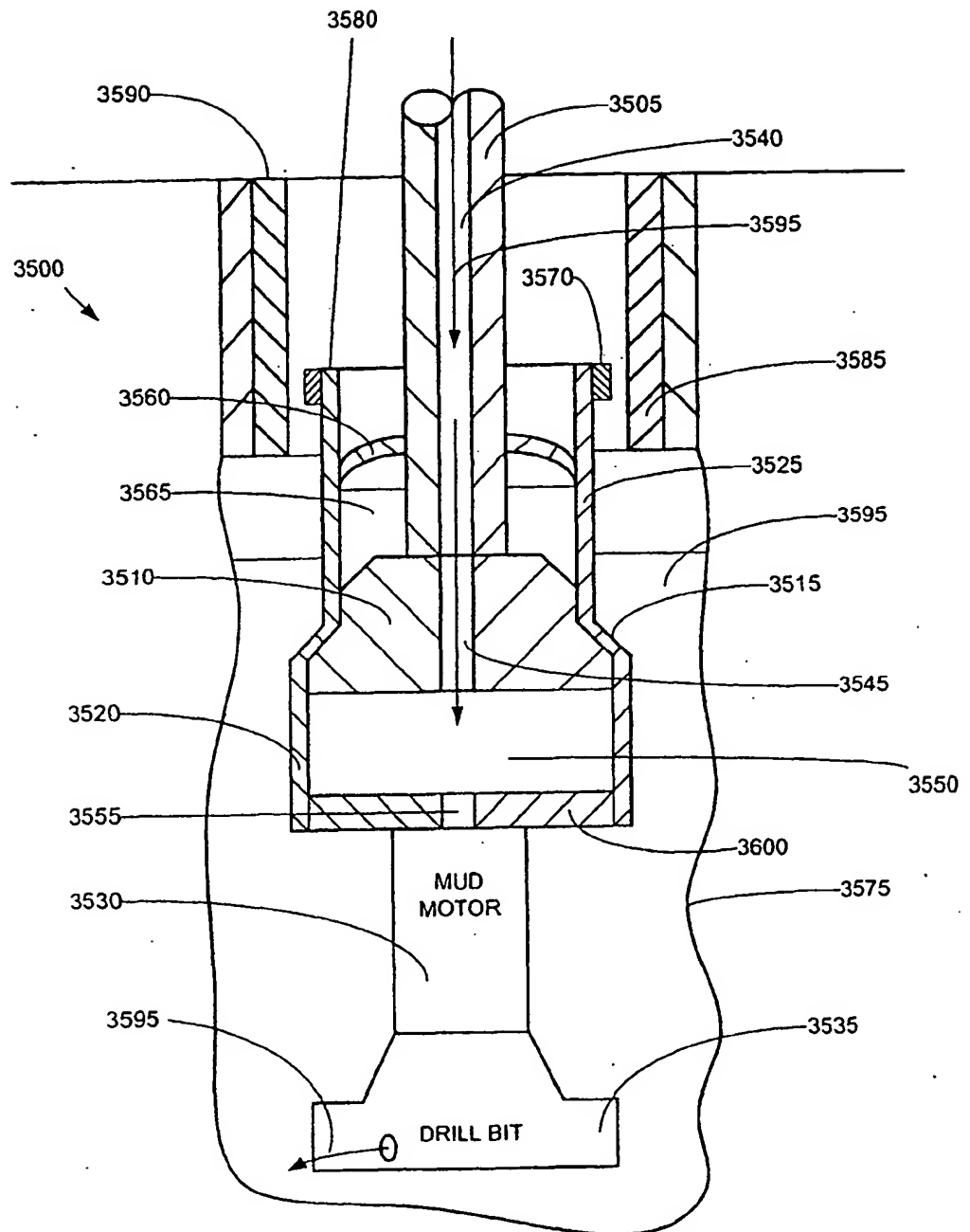


FIGURE 22B

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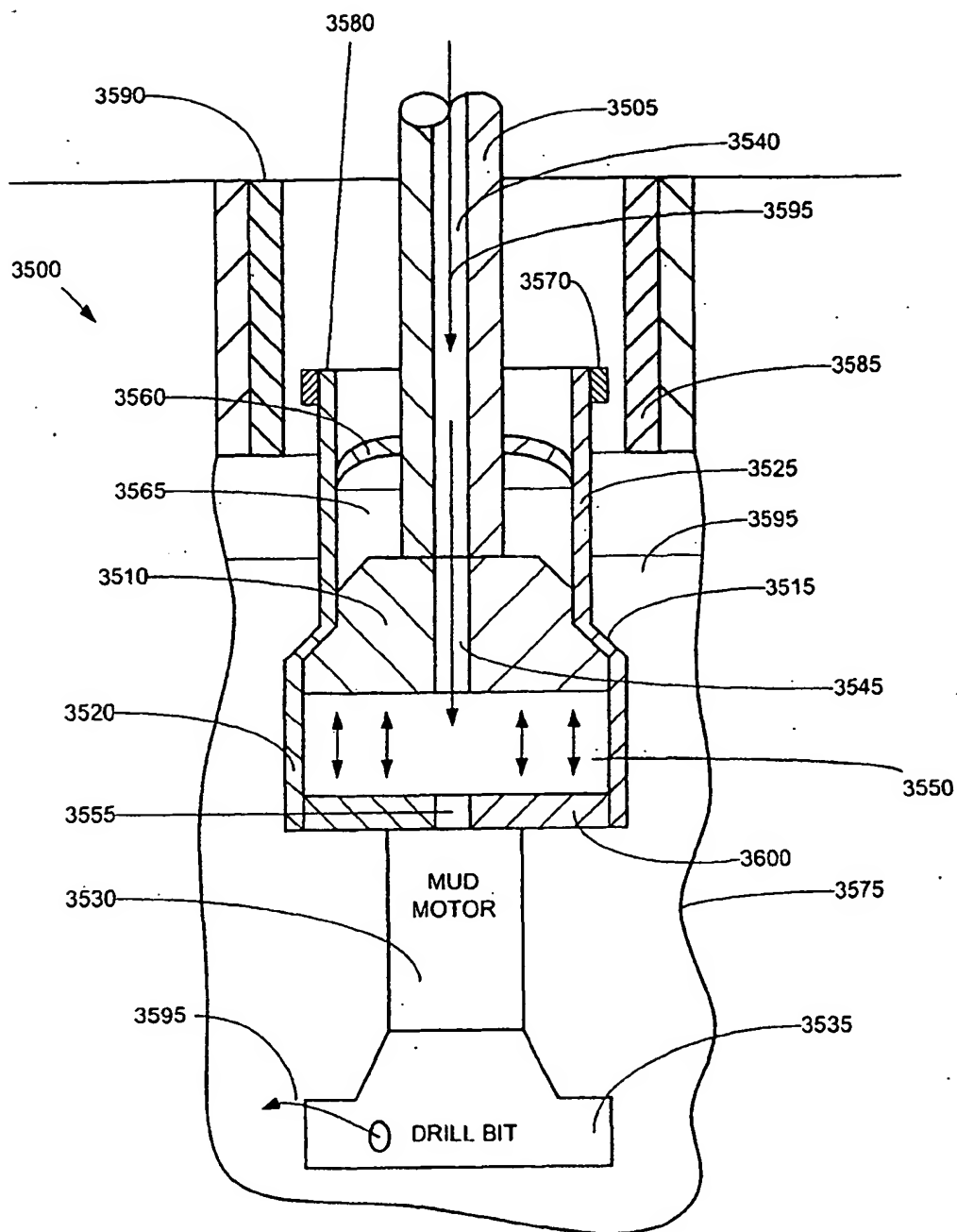
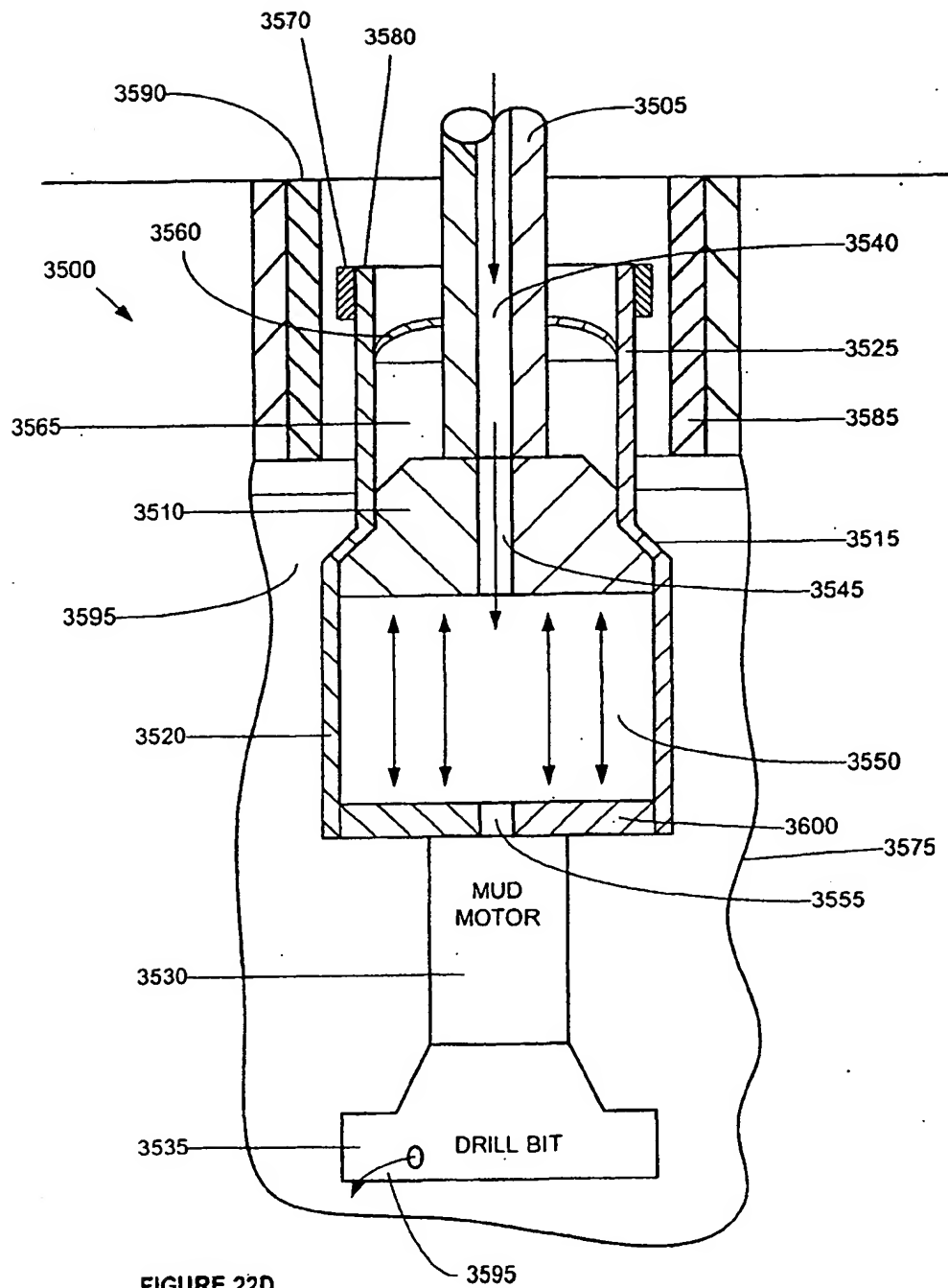


FIGURE 22C

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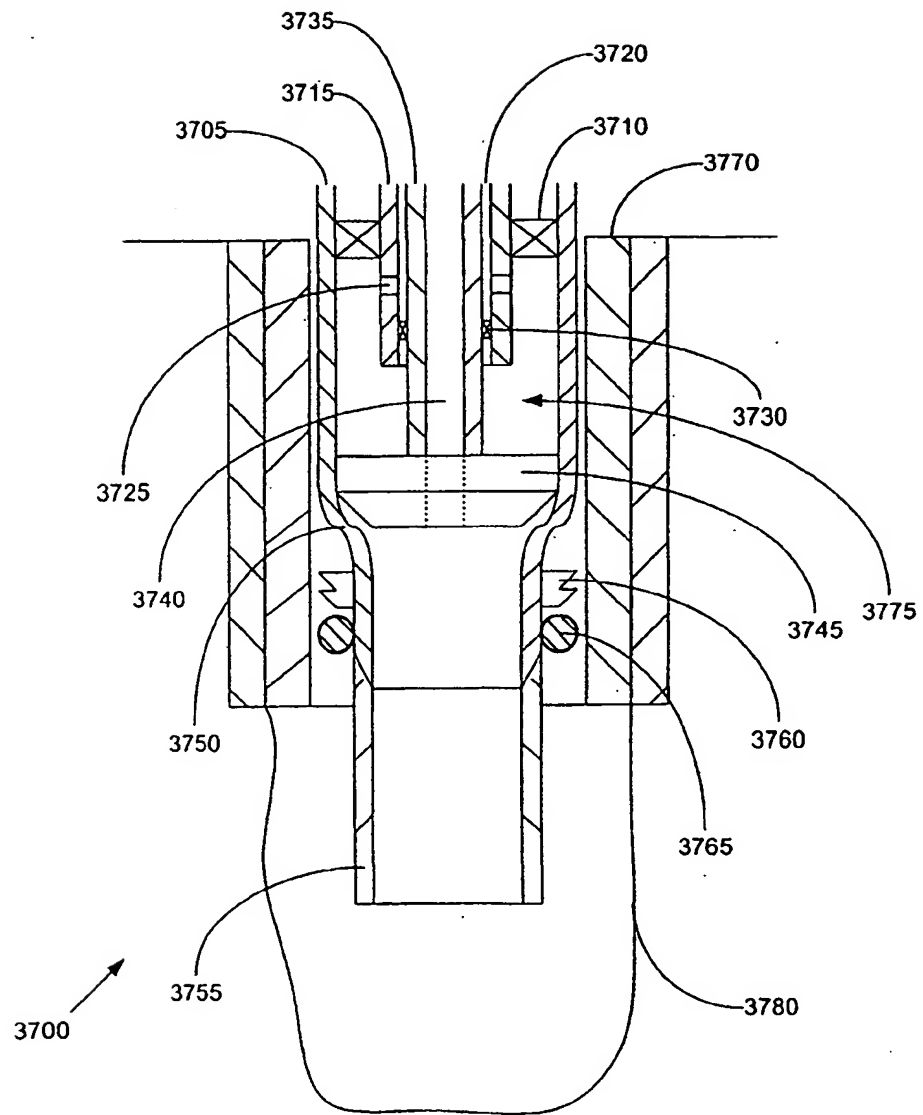


FIGURE 23A

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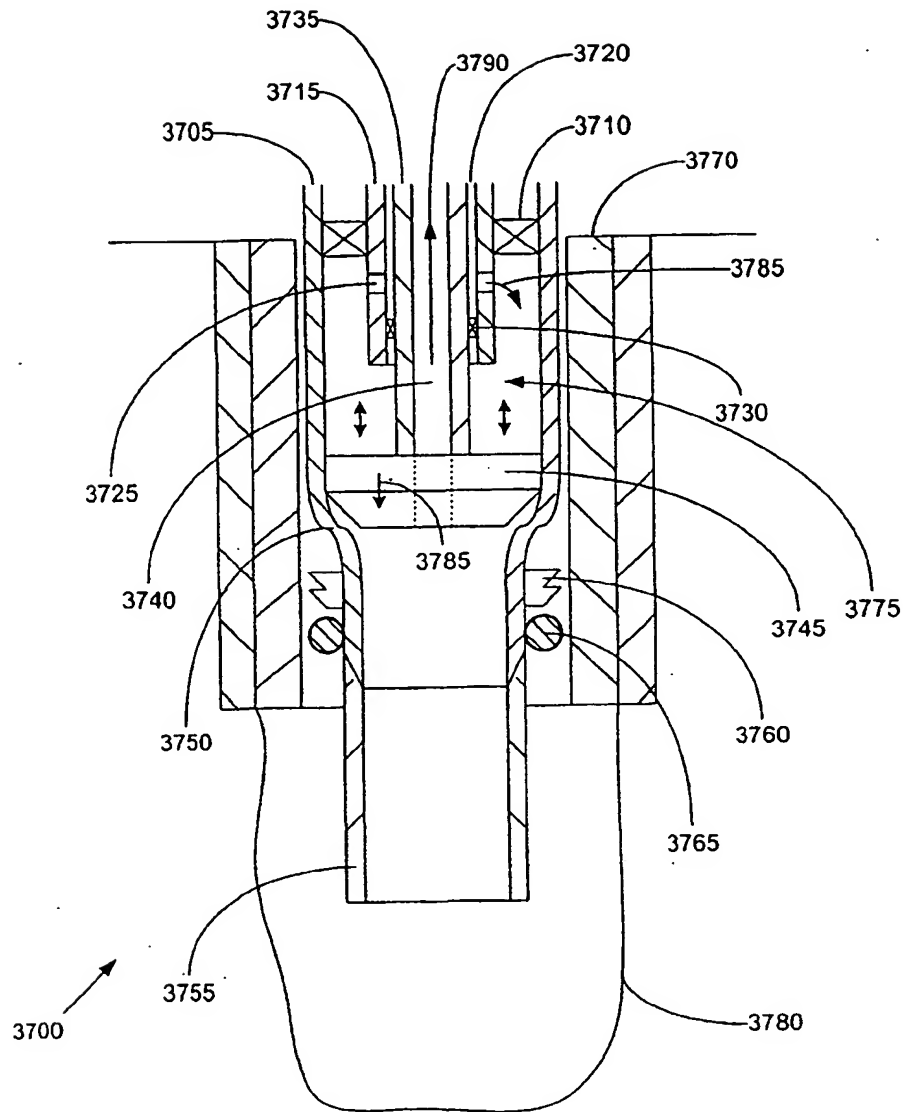


FIGURE 23B

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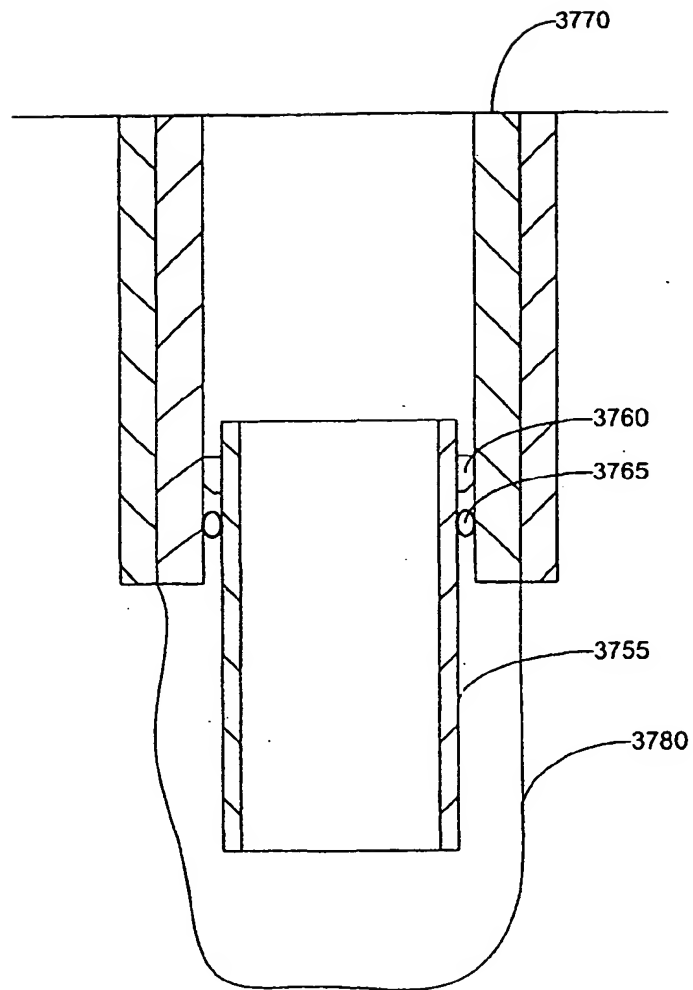


FIGURE 23C

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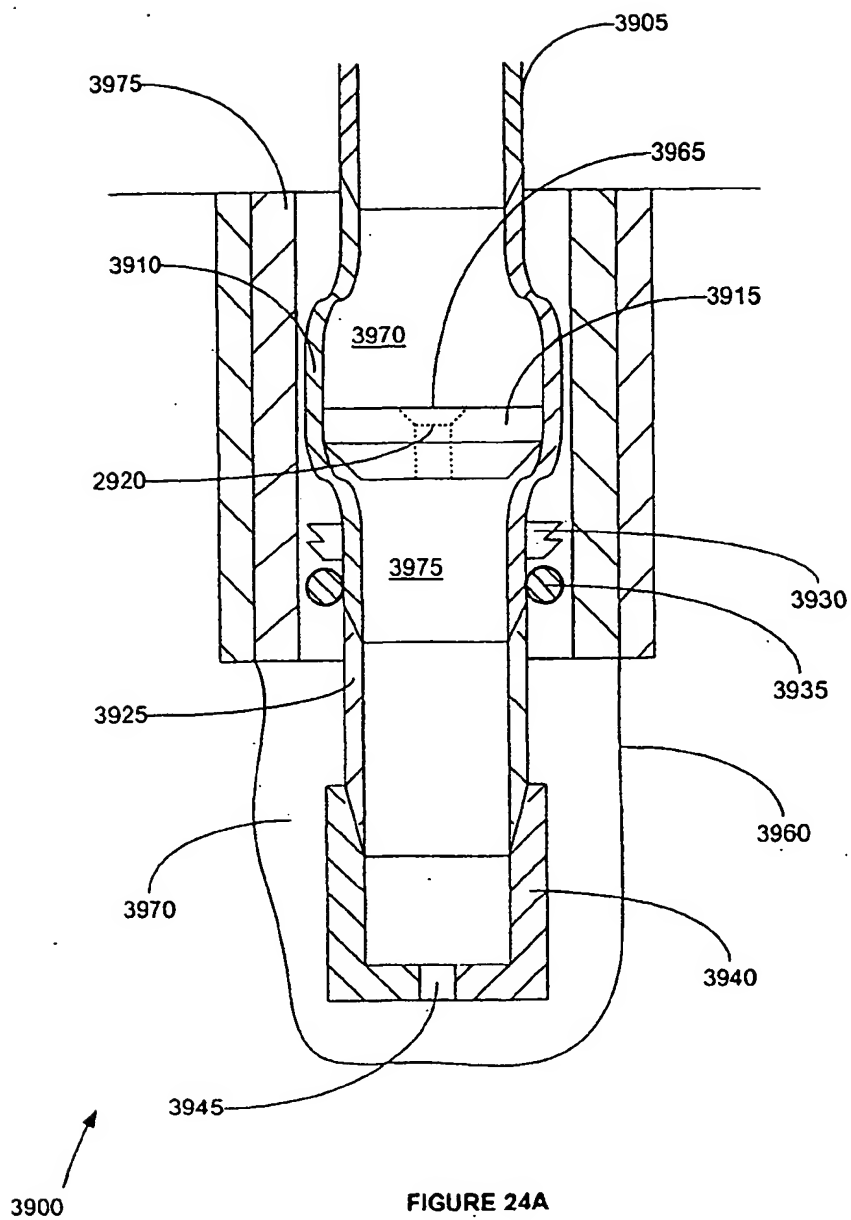


FIGURE 24A

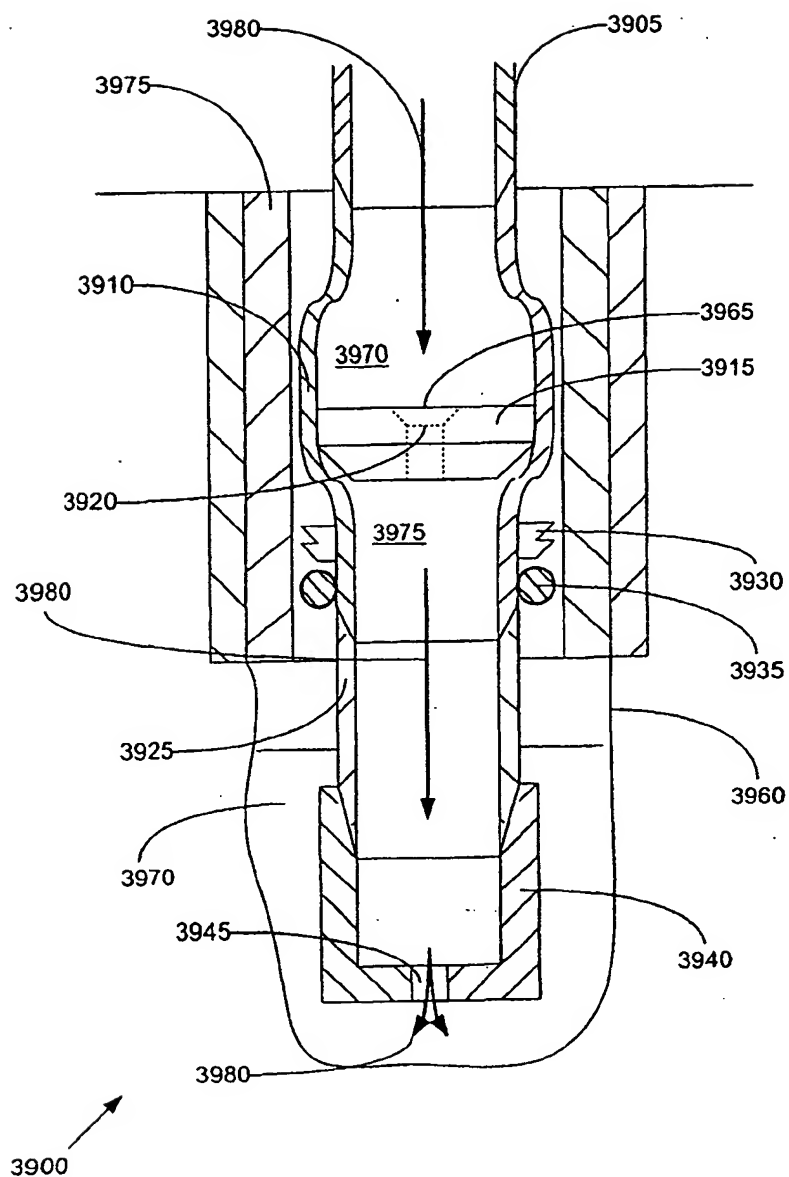


FIGURE 24B

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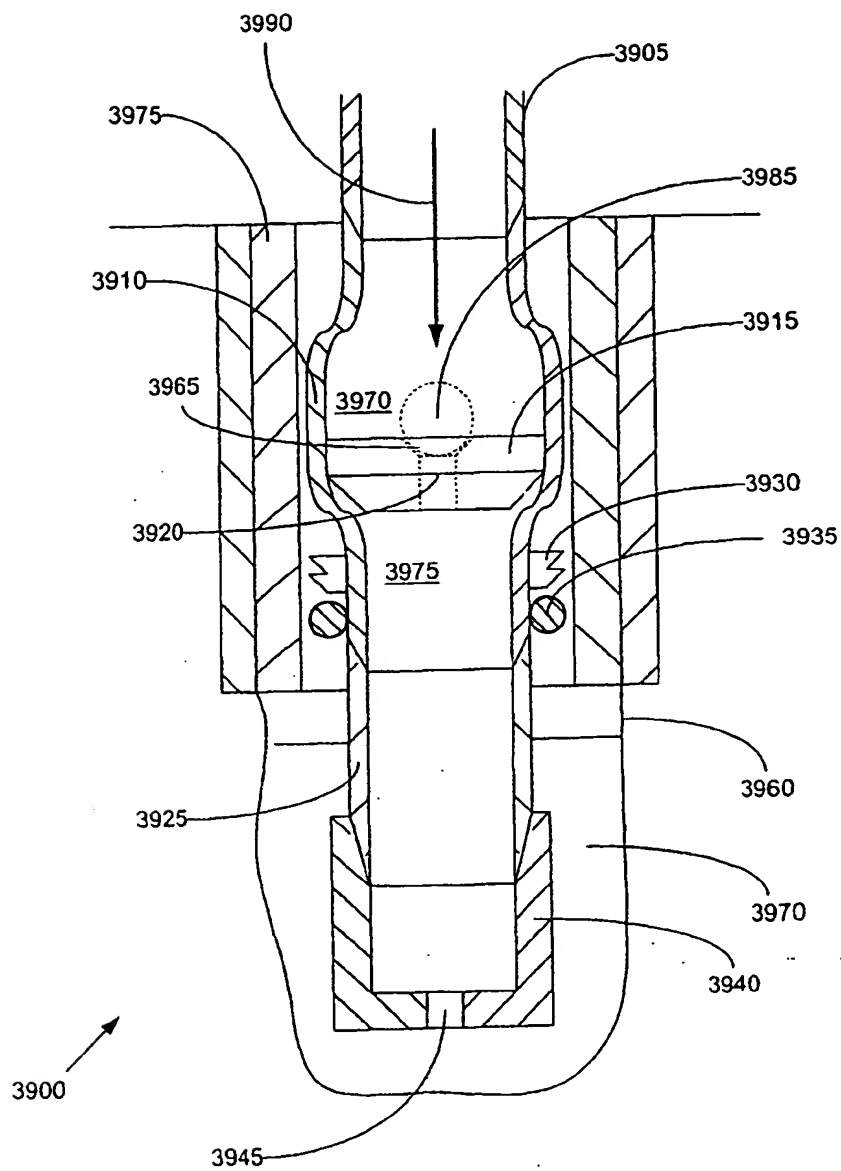


FIGURE 24C

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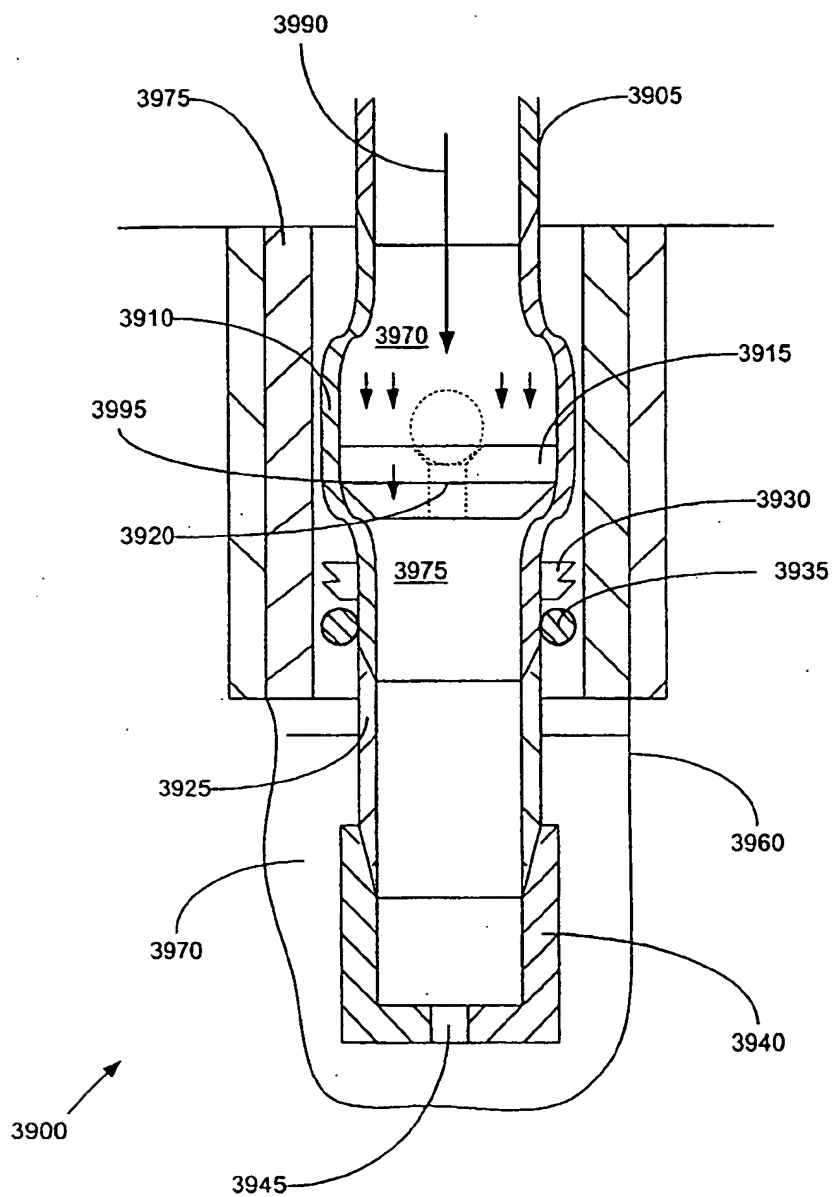


FIGURE 24D

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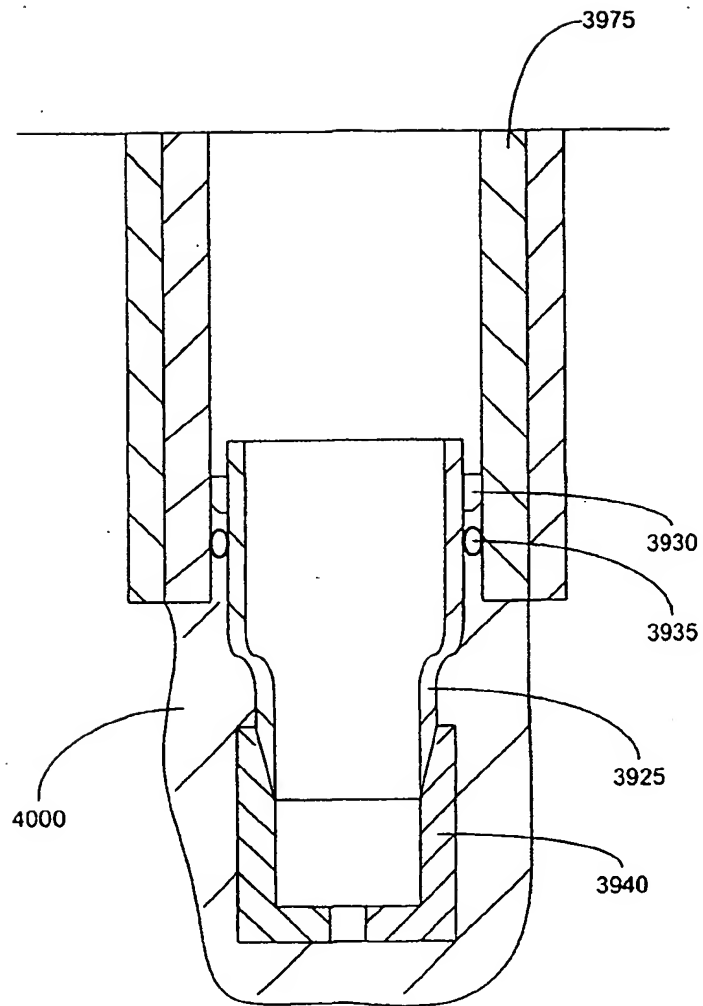


FIGURE 24E

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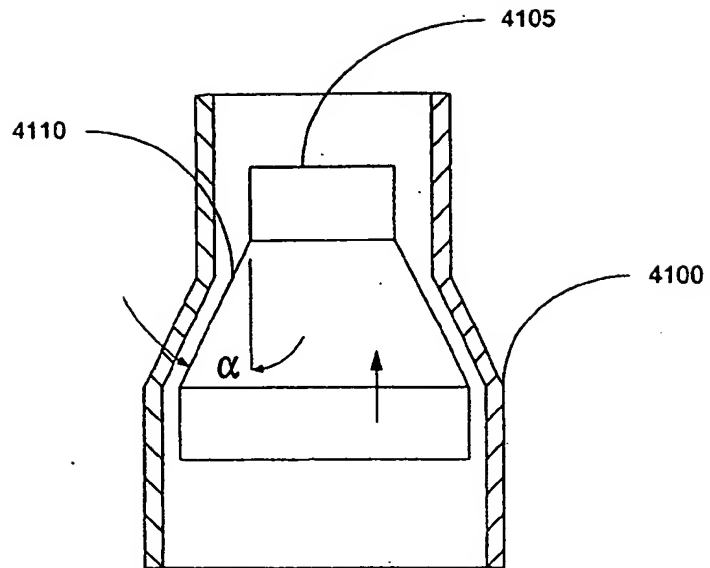


FIGURE 25

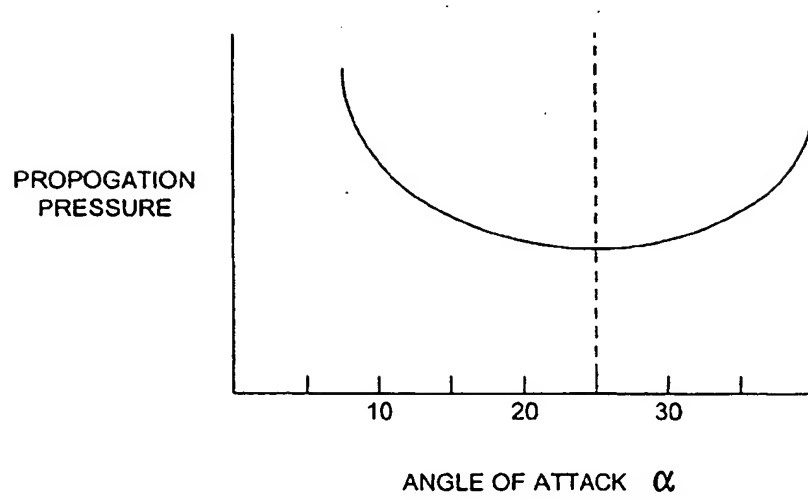


FIGURE 26

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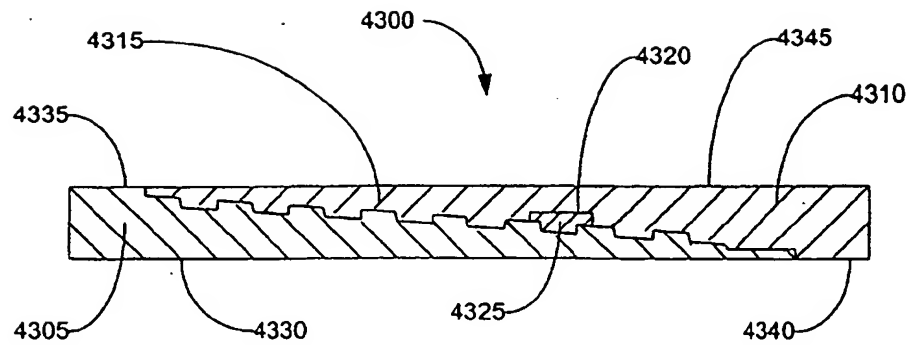


FIGURE 27

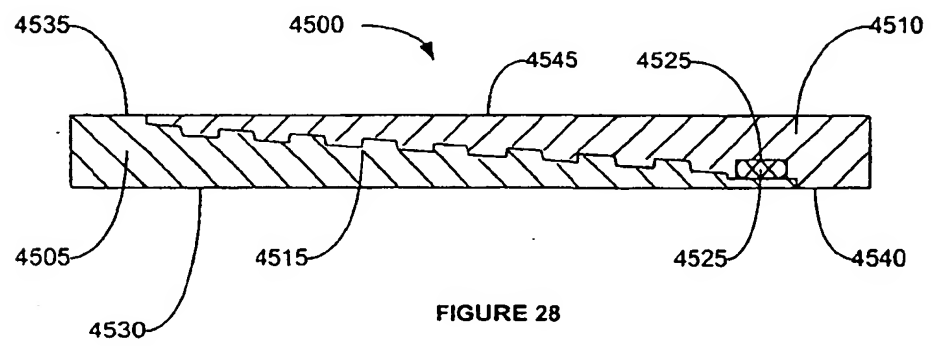


FIGURE 28

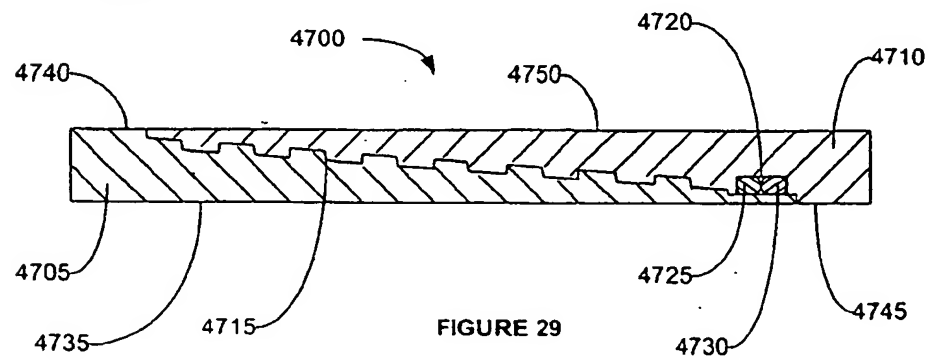


FIGURE 29

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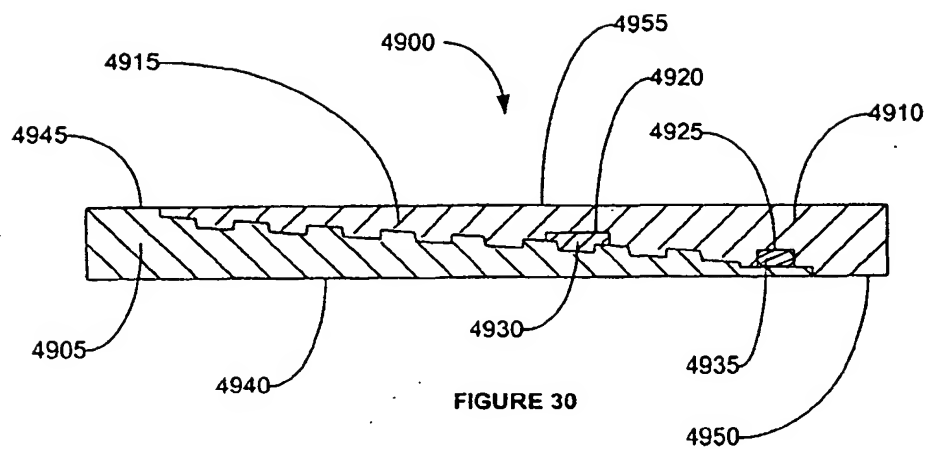


FIGURE 30

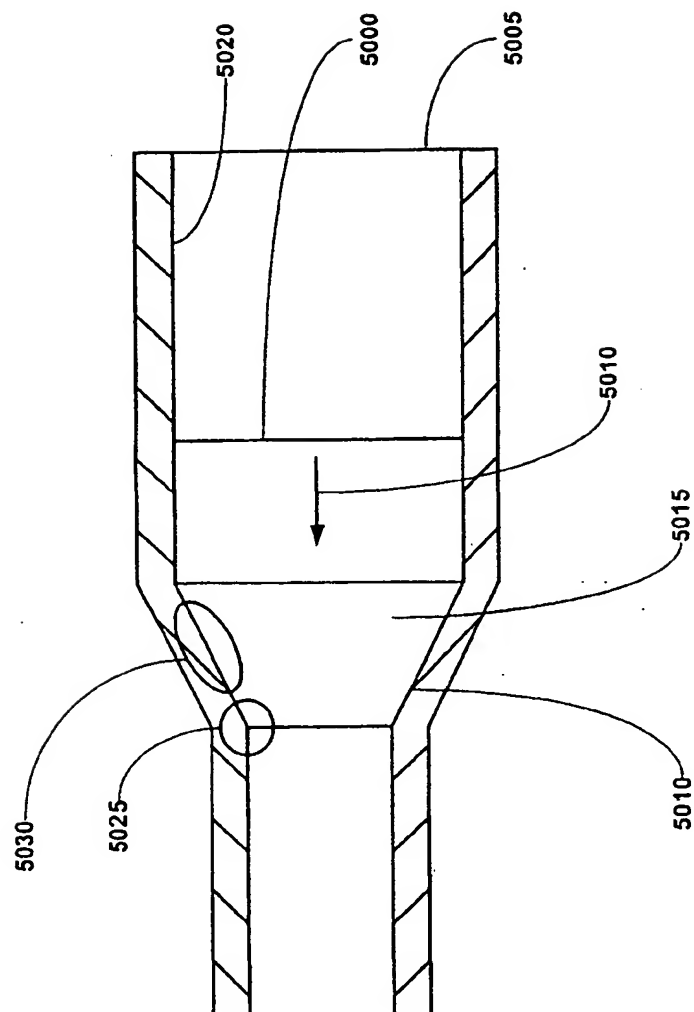
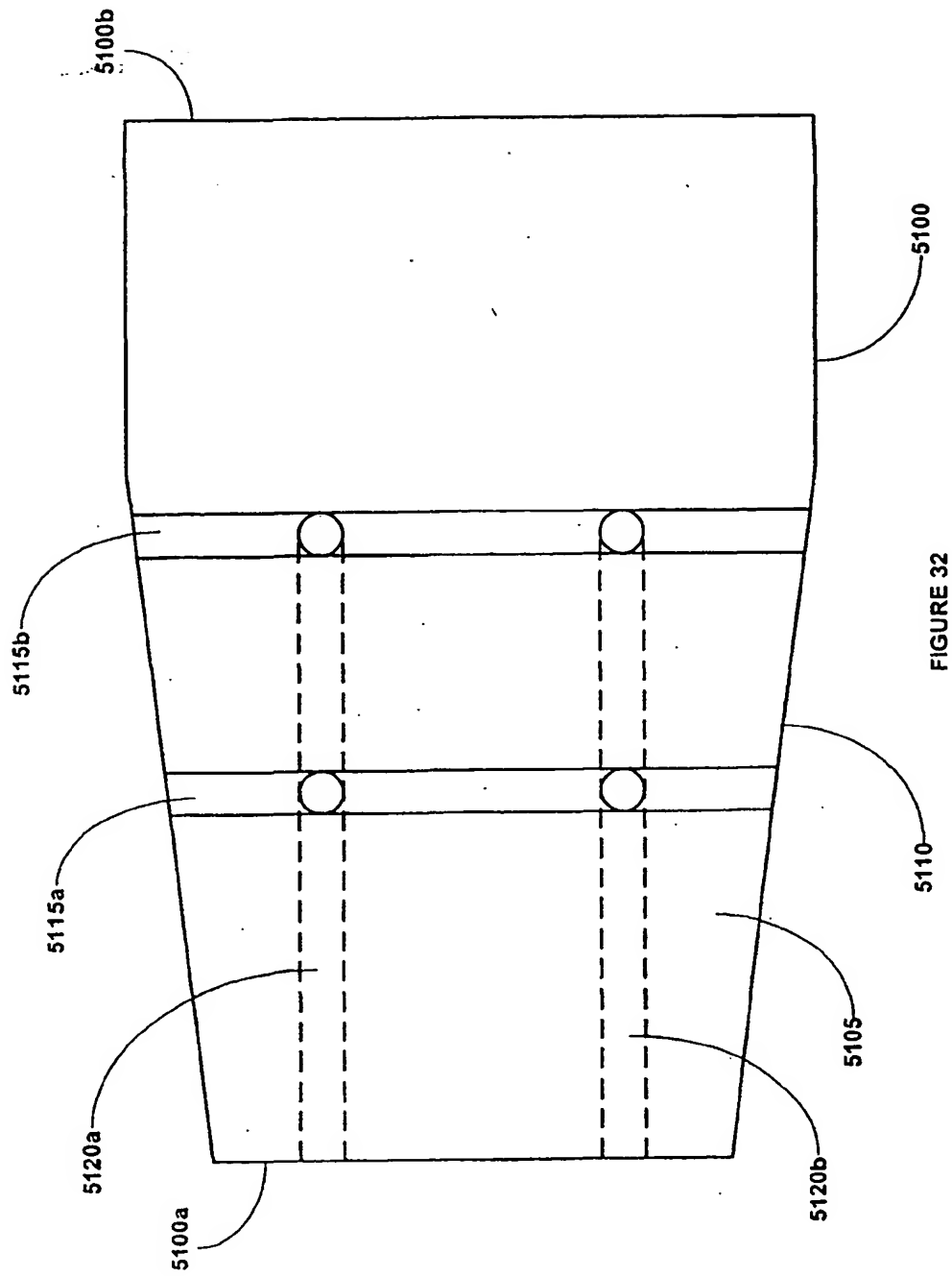


FIGURE 31



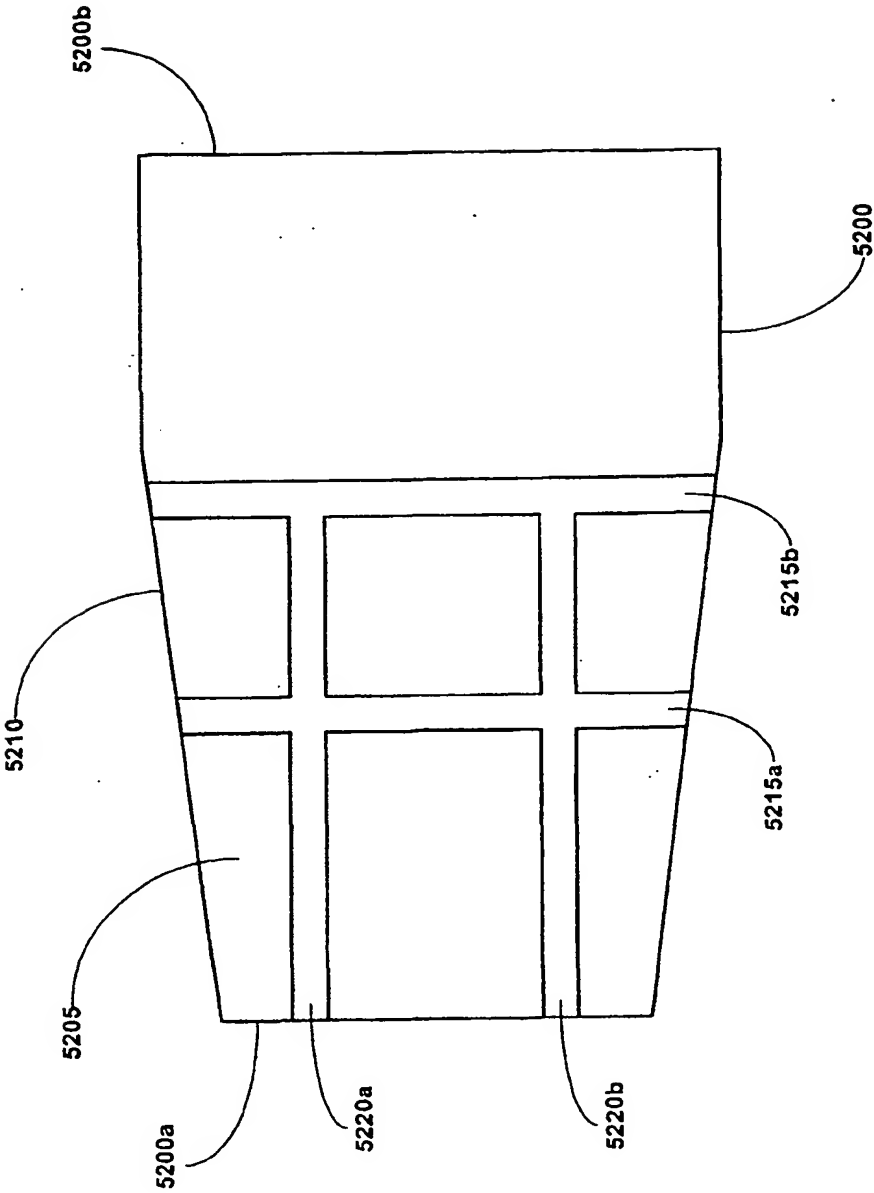


FIGURE 33

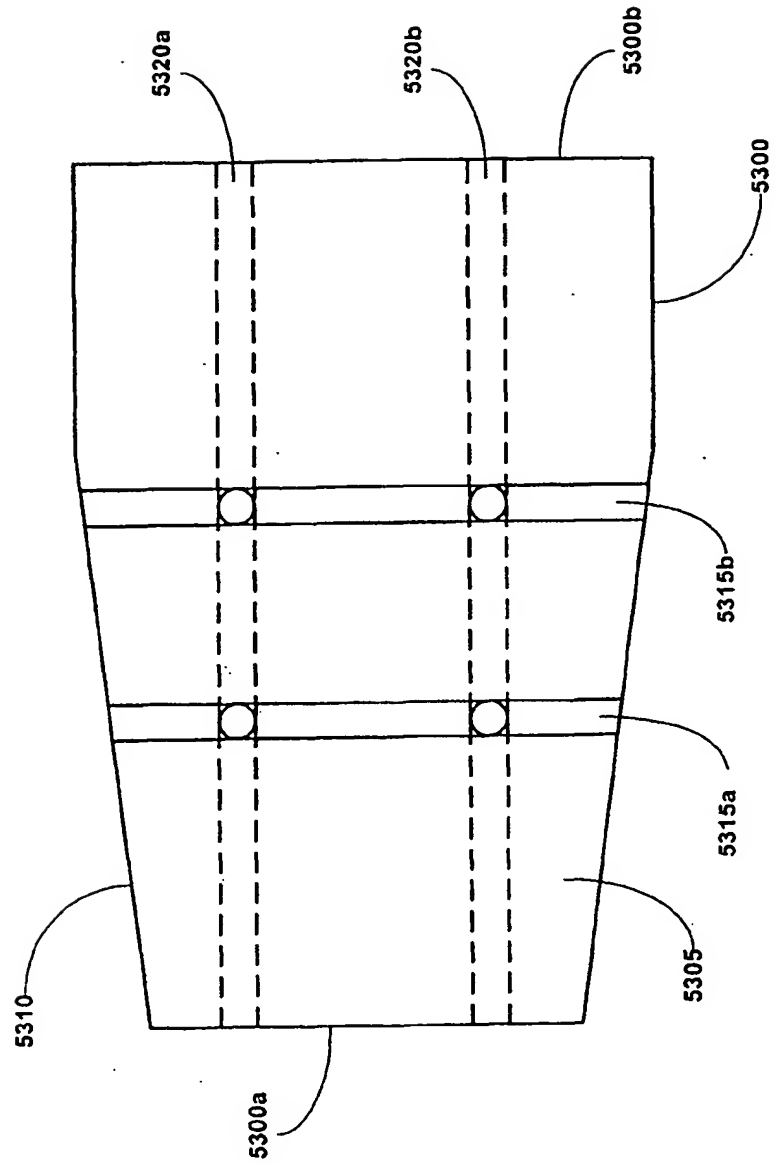


FIGURE 34

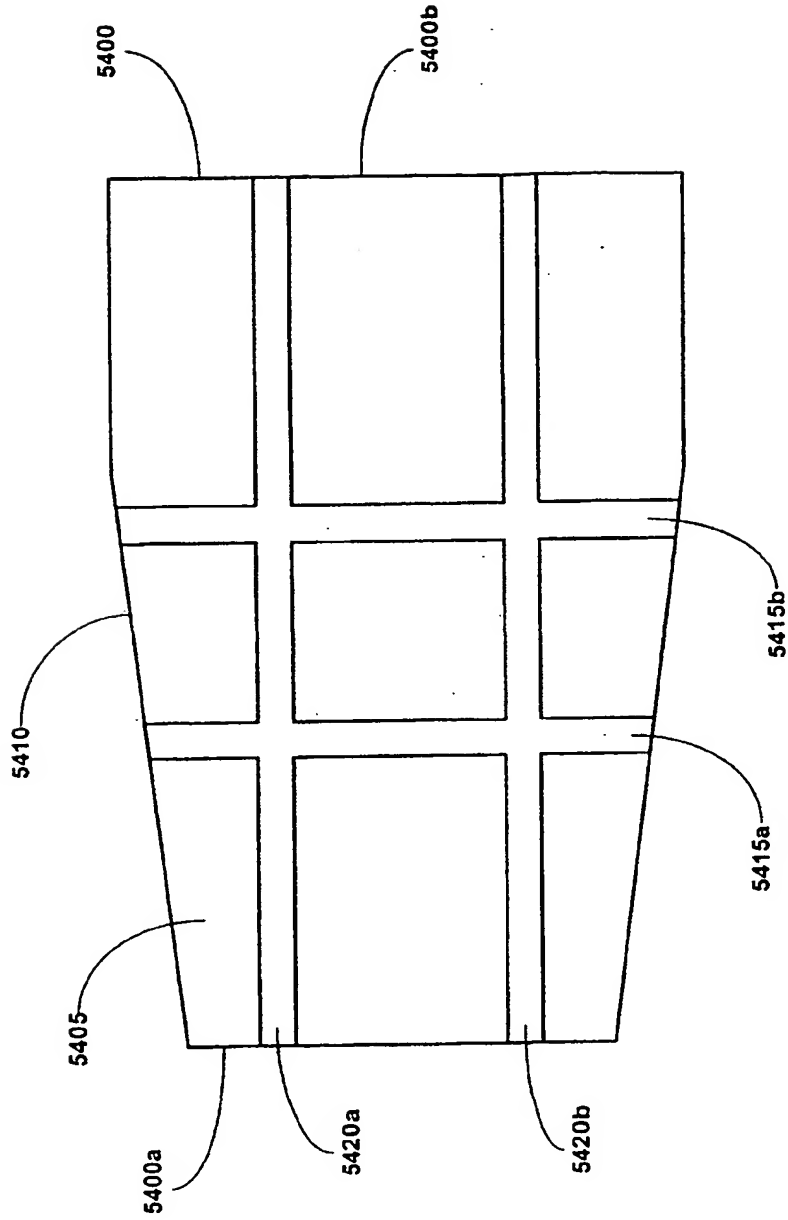


FIGURE 35

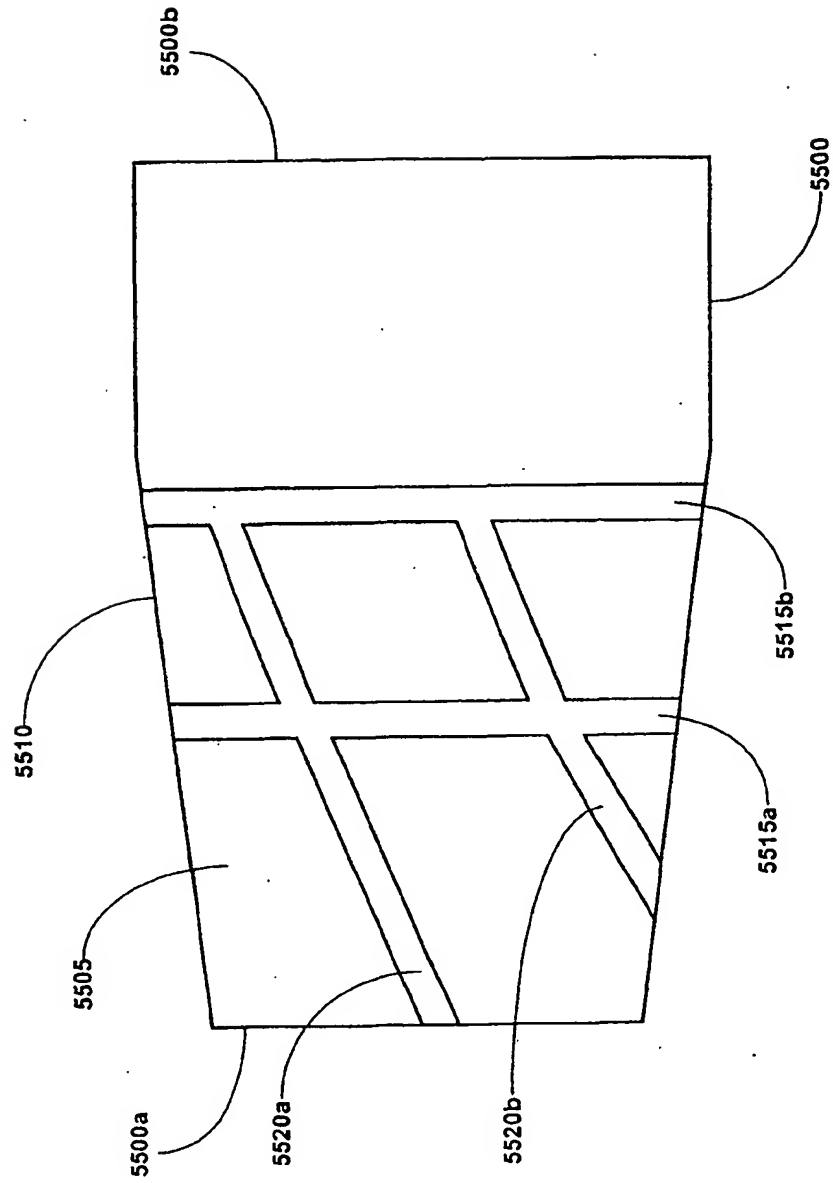


FIGURE 36

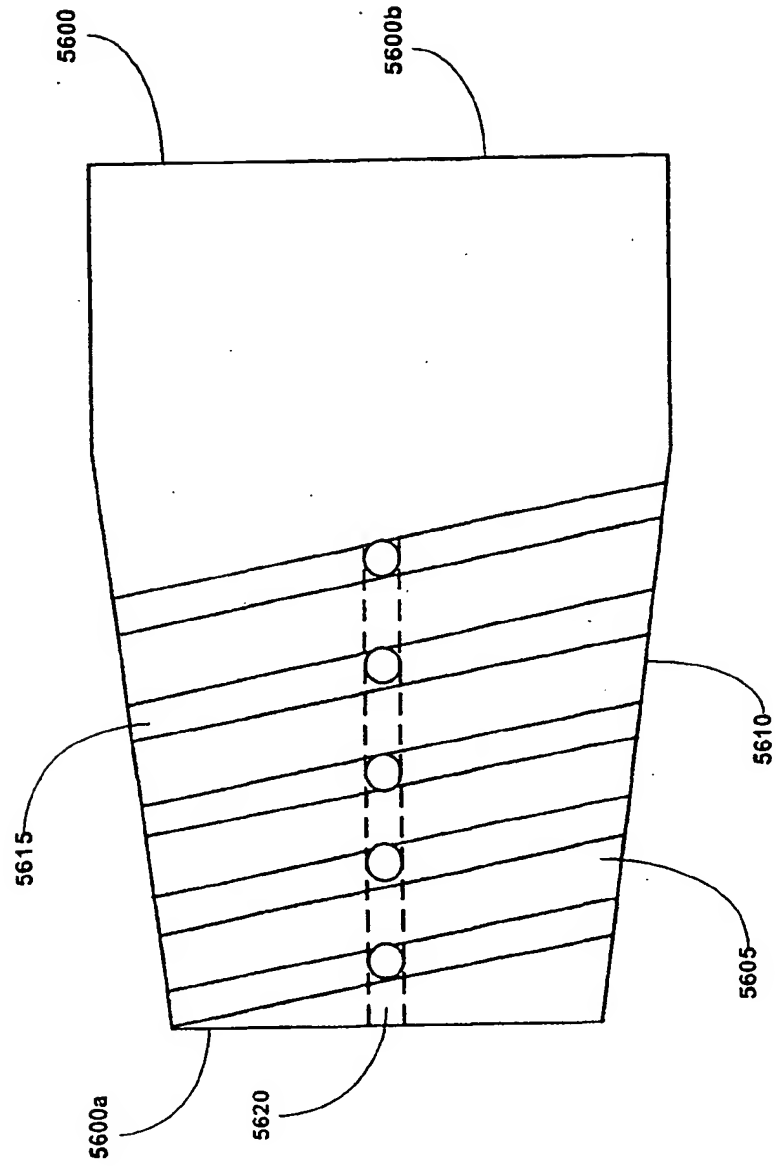


FIGURE 37

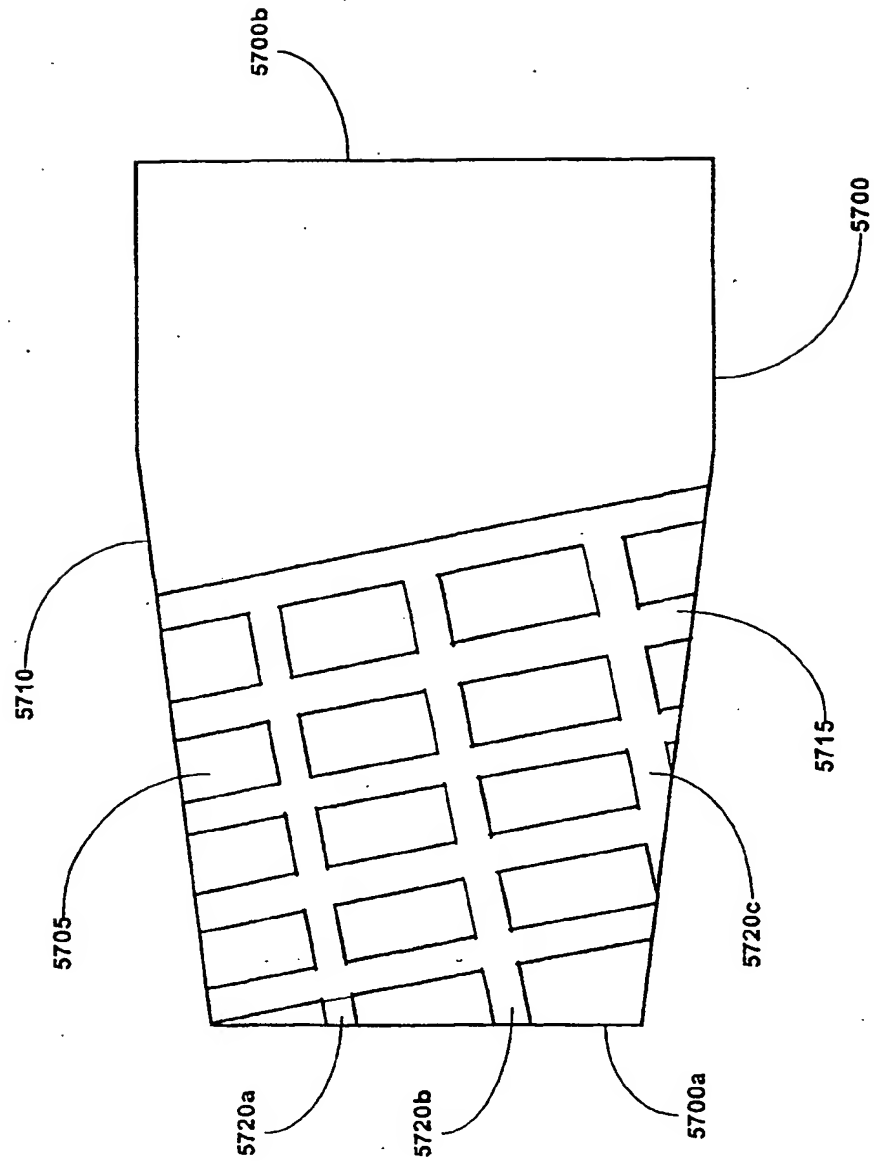


FIGURE 38

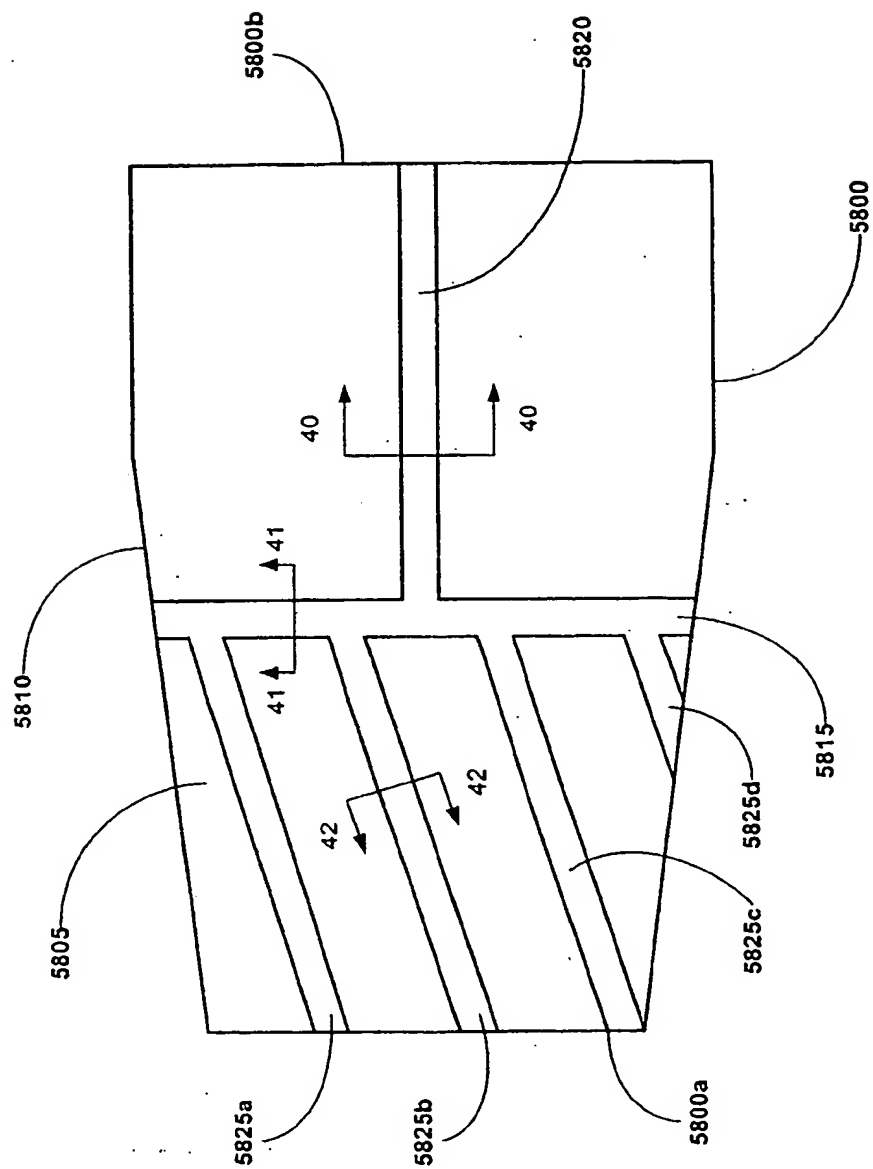


FIGURE 39

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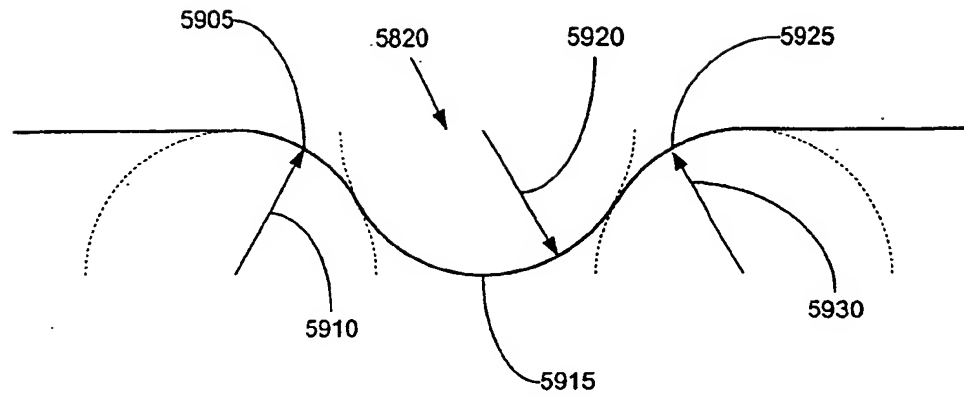


FIGURE 40

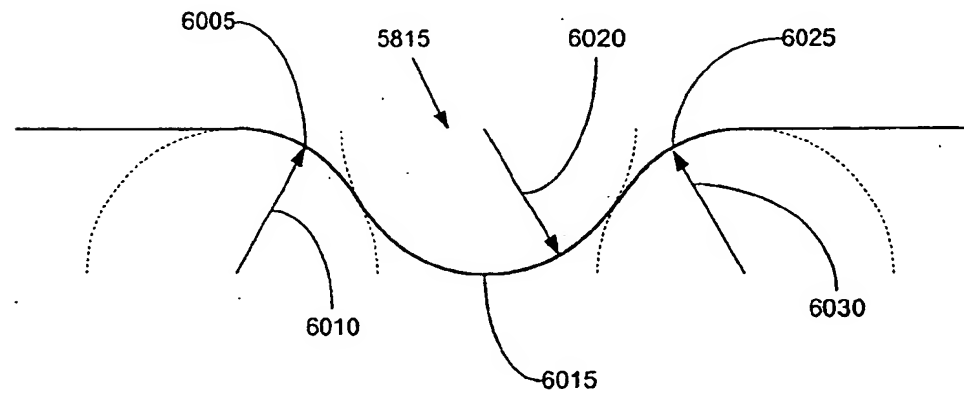


FIGURE 41

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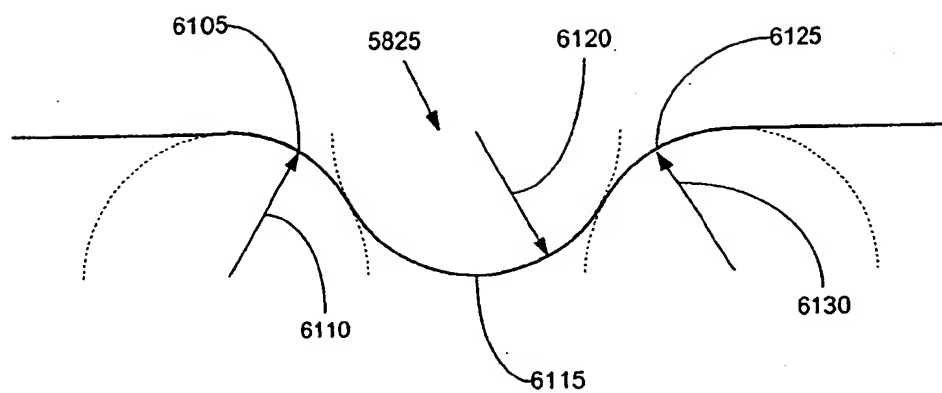


FIGURE 42

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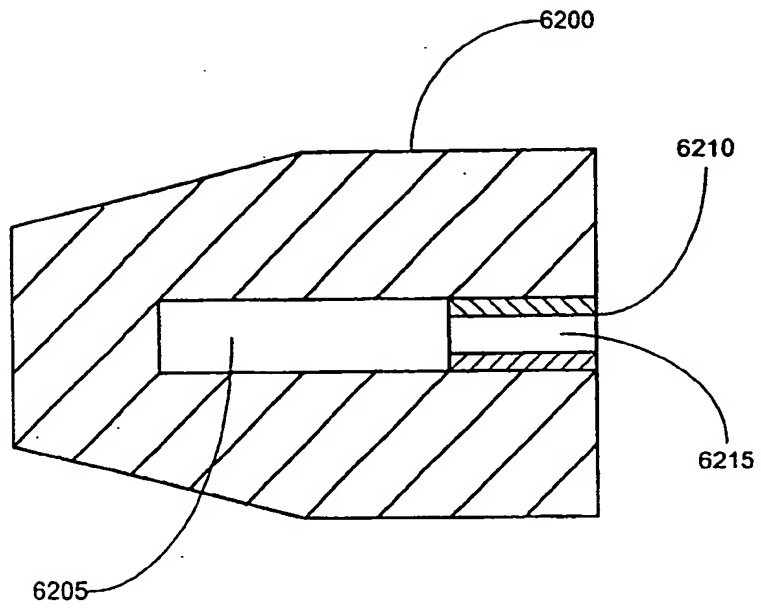


FIGURE 43

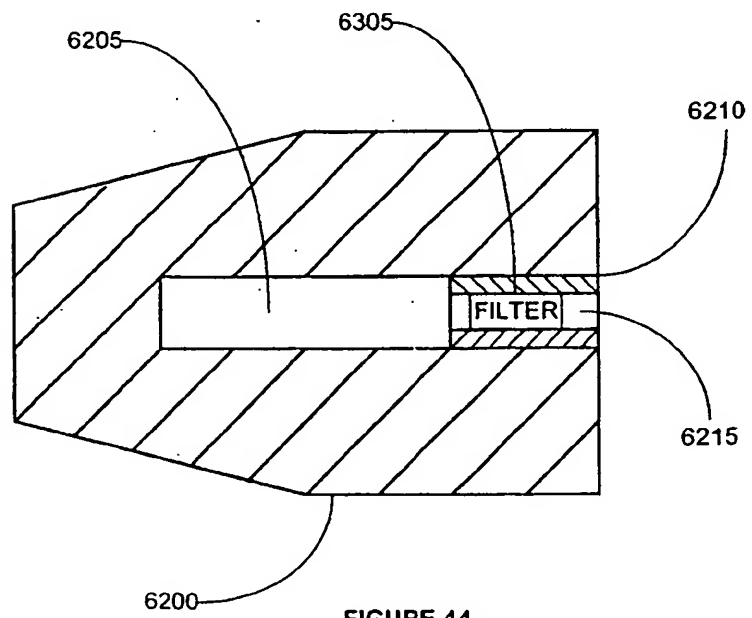


FIGURE 44

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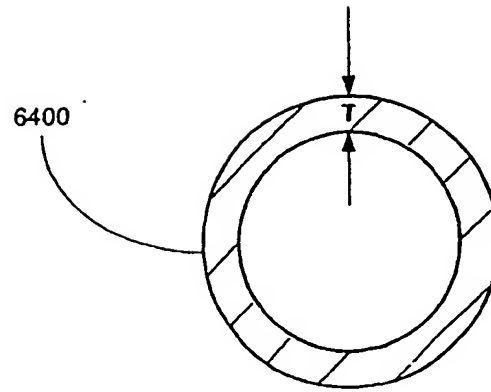


FIGURE 45

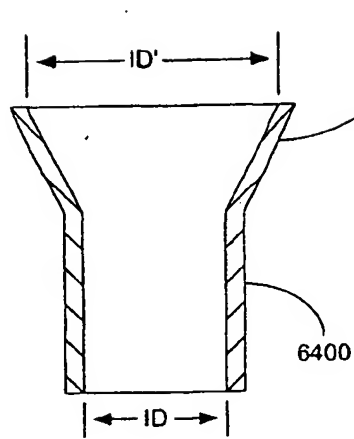


FIGURE 46

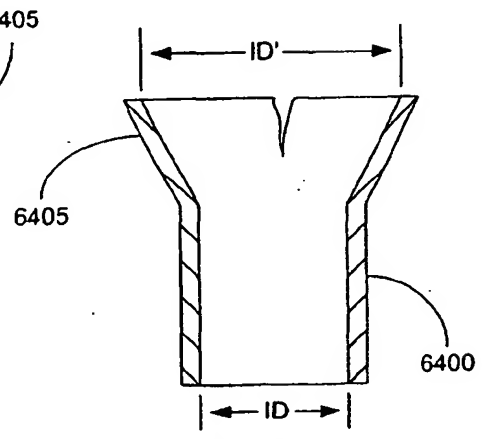


FIGURE 47

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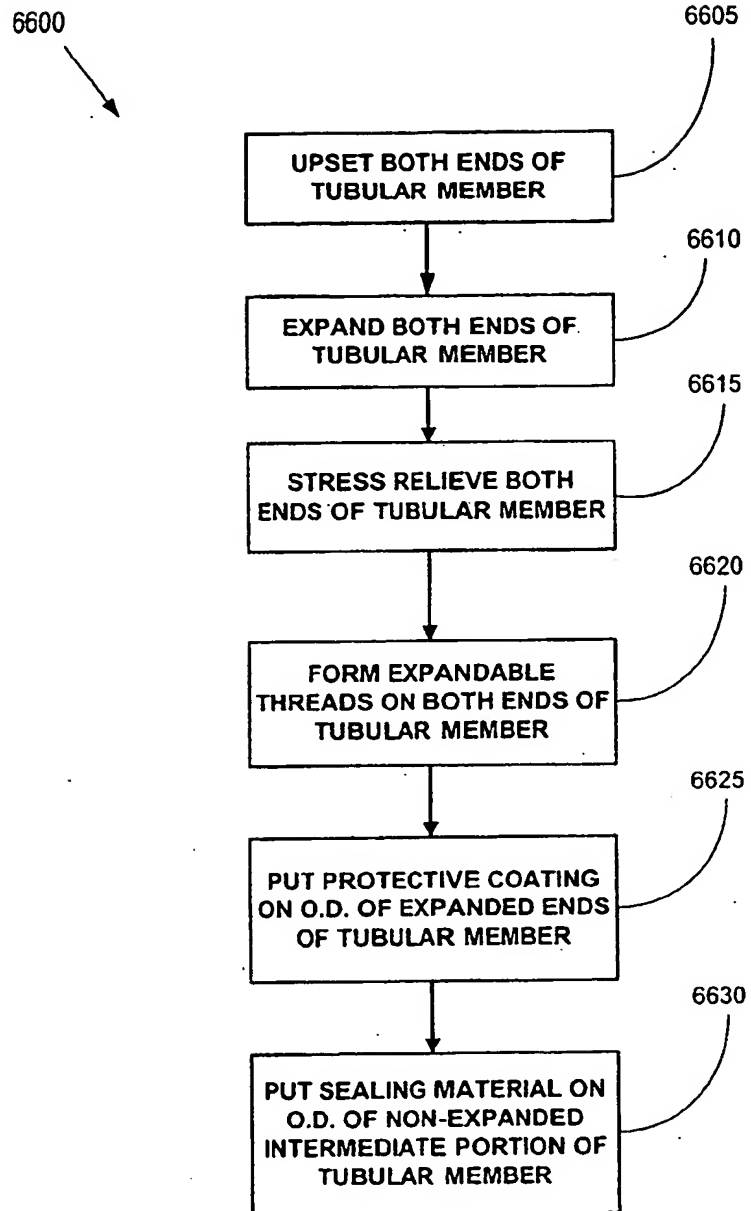
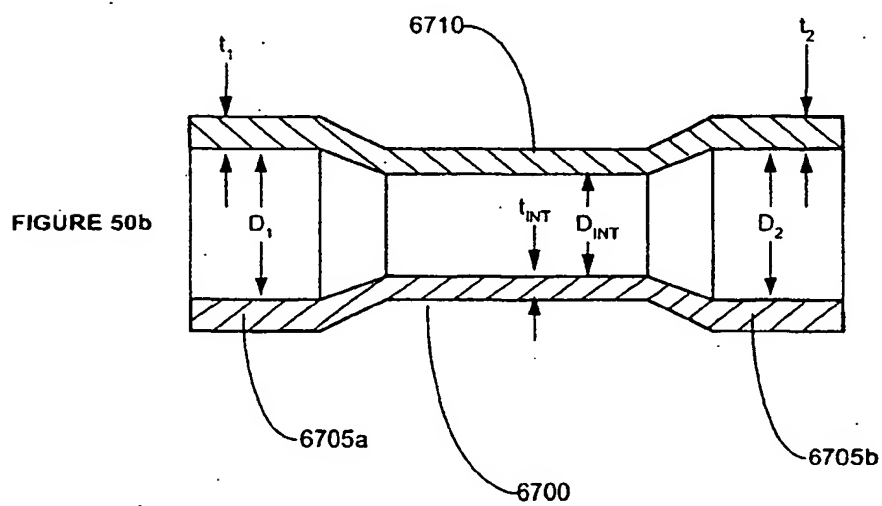
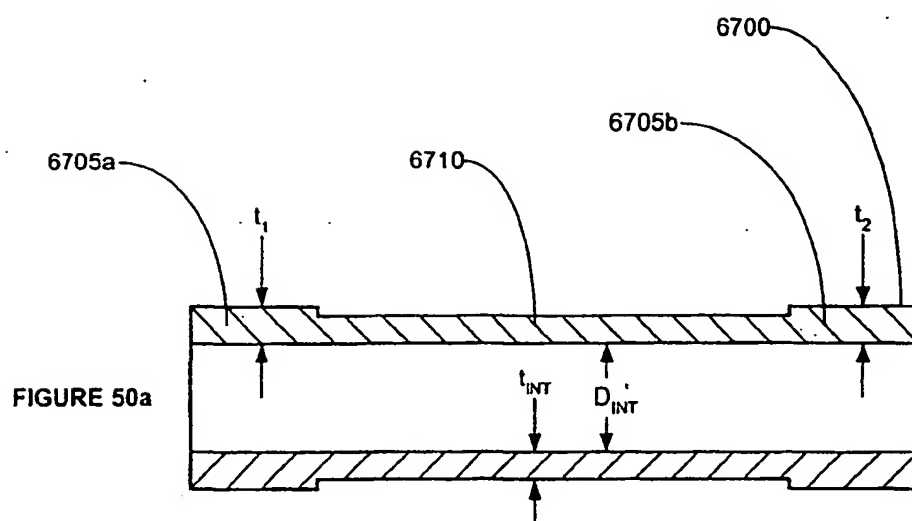


FIGURE 49

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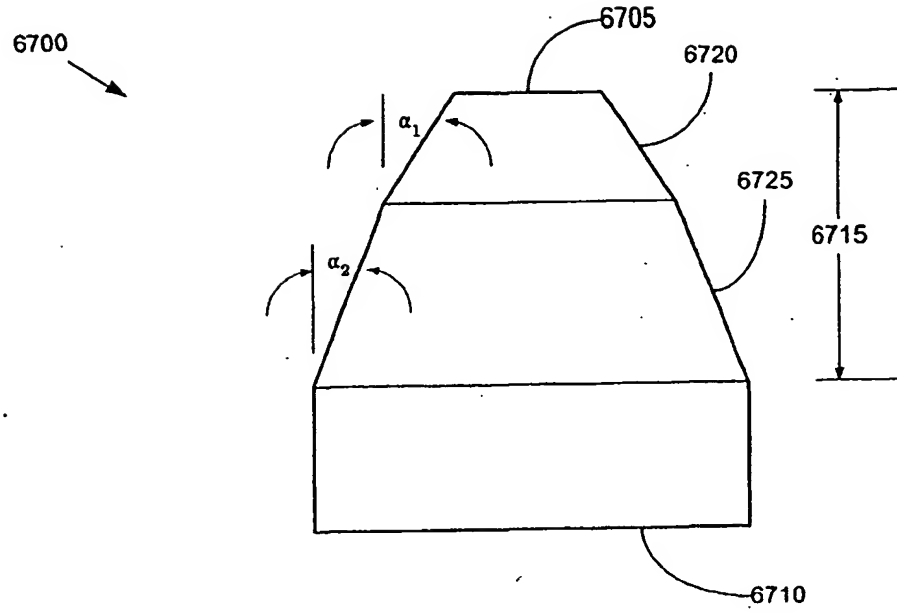
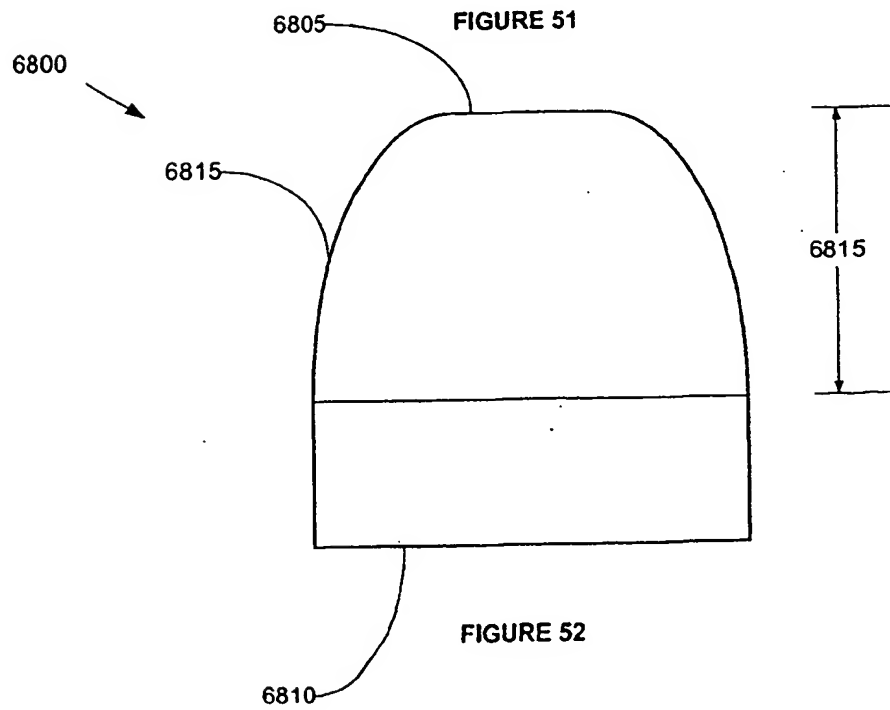
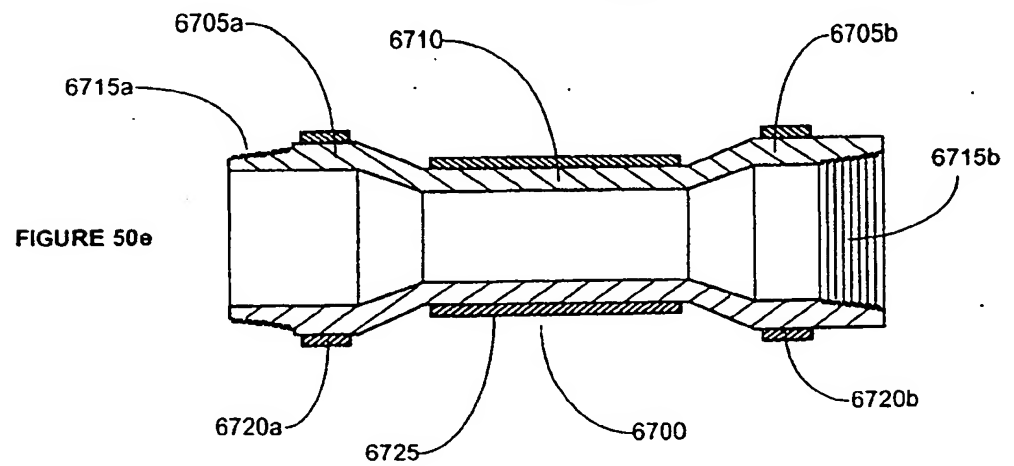
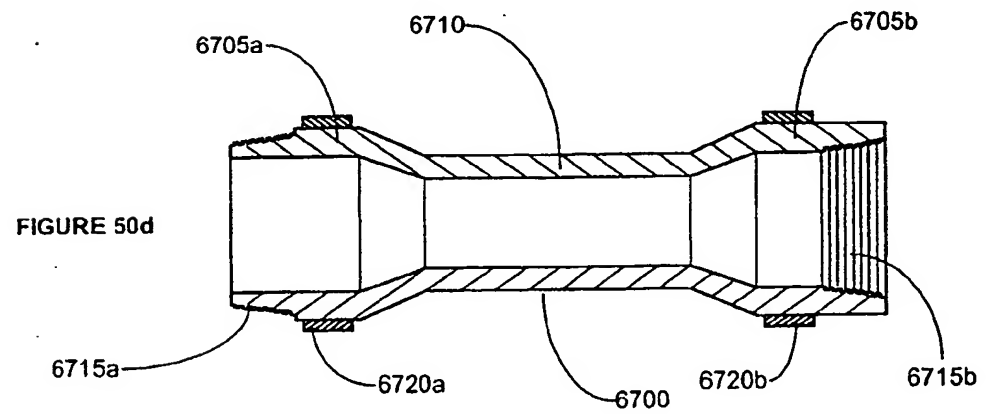
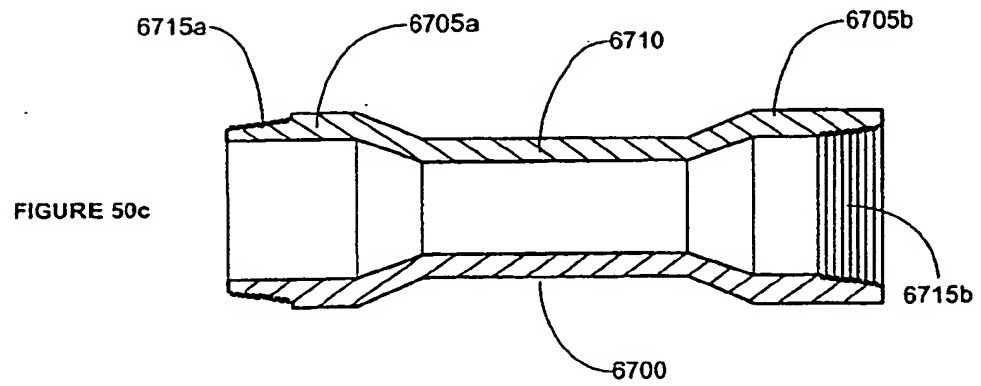


FIGURE 51



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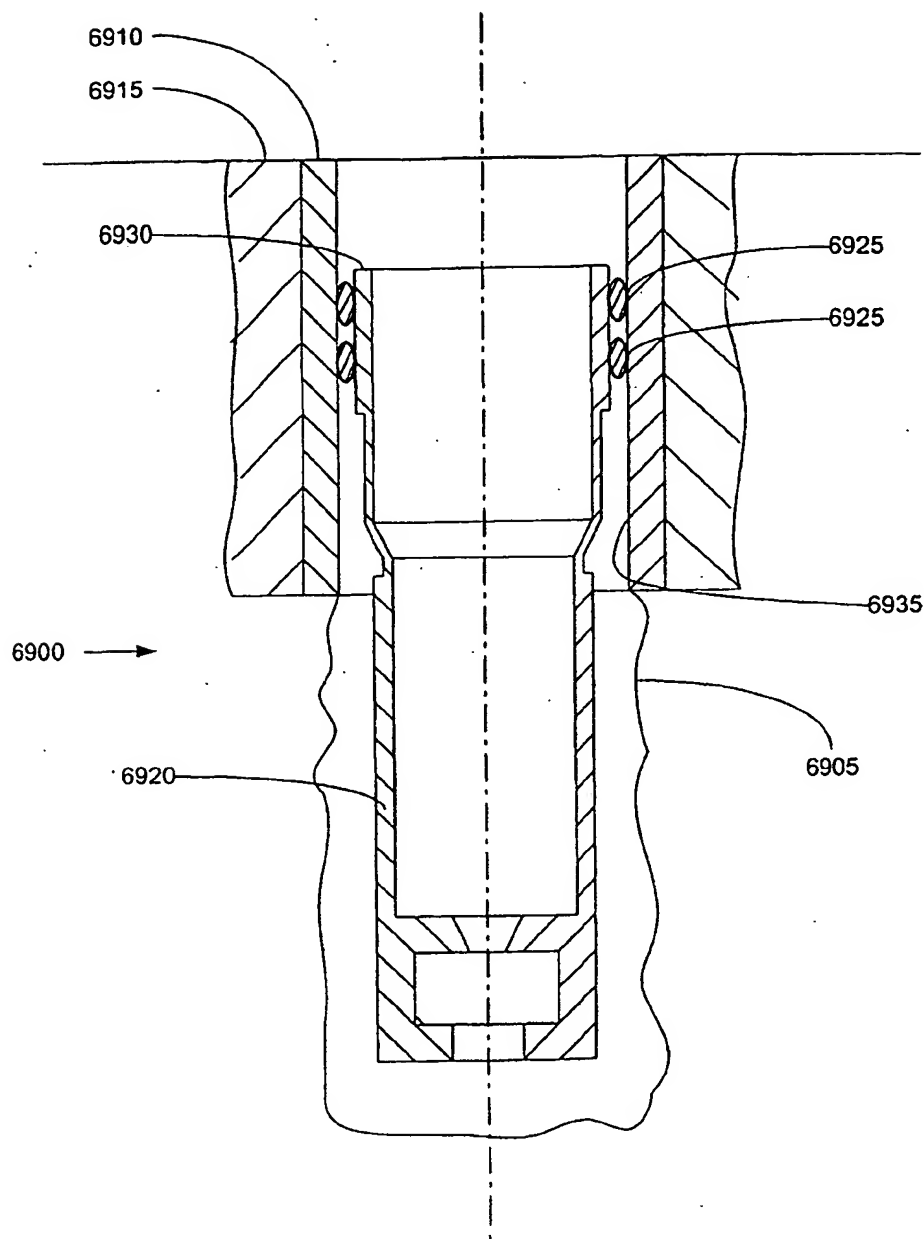


FIGURE 53a

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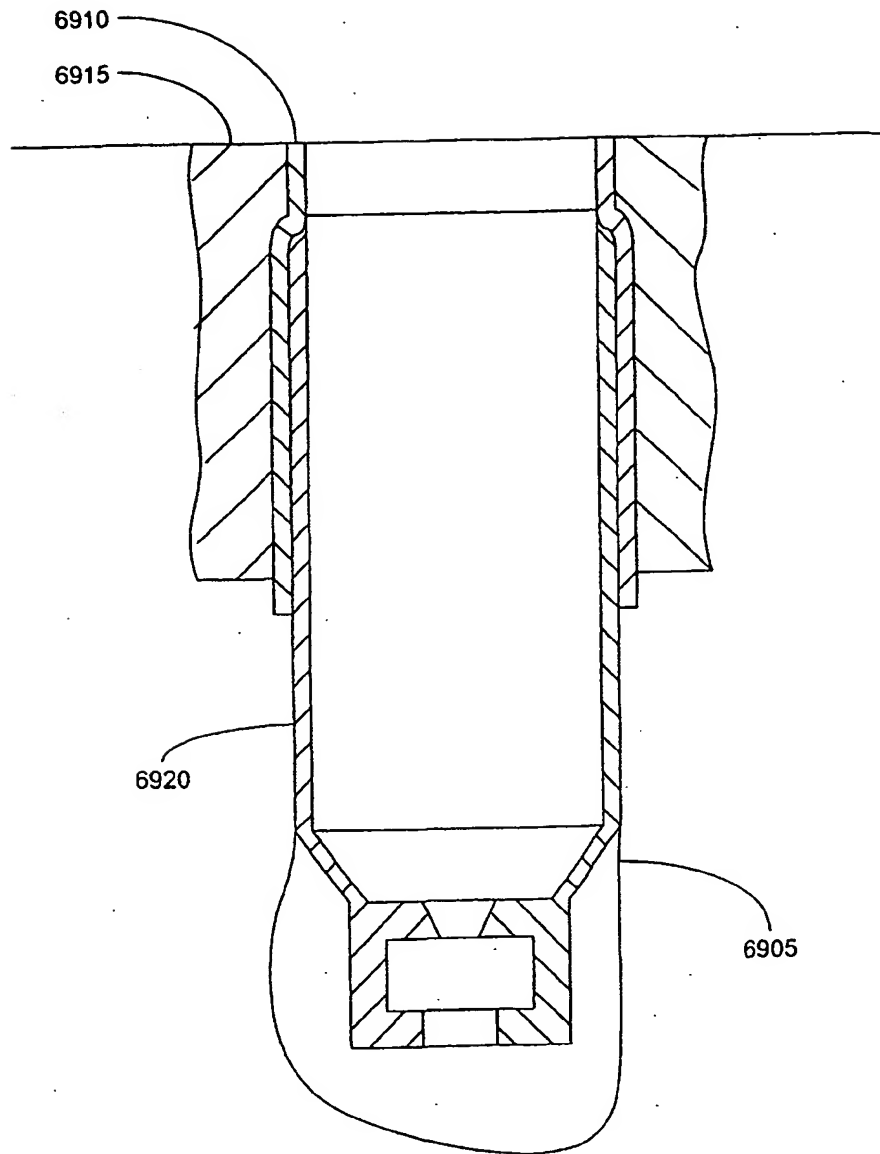


FIGURE 53c

INTERNATIONAL SEARCH REPORT

 International application No.
 PCT/US00/18635

A. CLASSIFICATION OF SUBJECT MATTER

IPC(7) : F16L 55/16

US CL : 138/98

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

U.S. : 138/98, 97; 29/409.09, 890.036, 523; 228/107, 119, 183

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 5,787,933 A (RUSS et al) 04 August 1998, entire document.	1-3 and 6
X	US 5,368,075 A (BARO et al) 29 November 1994, entire document.	4 and 5
A	US 4,941,512 A (McPARLAND) 17 July 1990, entire document.	1-7
A	US 4,739,916 A (AYRES et al) 26 April 1988, entire document.	1-7
A	US 4,592,577 A (AYRES et al) 03 June 1986, entire document.	1-7

☐ Further documents are listed in the continuation of Box C.
 ☐ See patent family annex.

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A document defining the general state of the art which is not considered to be of particular relevance	*X* document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
E earlier document published on or after the international filing date	*Y* document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
L document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)	*A* document member of the same patent family
O document referring to an oral disclosure, use, exhibition or other means	
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Date of the actual completion of the international search

27 SEPTEMBER 2000

Date of mailing of the international search report

24 NOV 2000

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**(19) World Intellectual Property Organization
International Bureau**



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(10) International Publication Number

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(51) International Patent Classification⁷: F16L 55/16

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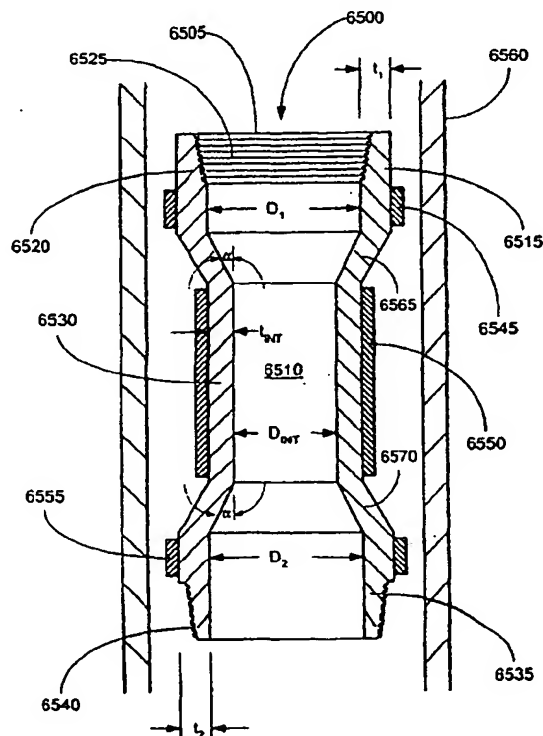
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[Continued on next page]

(54) Title: TWO-STEP RADIAL EXPANSION



(57) Abstract: A two-step radial expansion process. A first tubular member (6530) is radially expanded into contact with the interior surface of a second tubular member (6550). Both tubular members are then radially expanded.

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AMENDED CLAIMS

[received by the International Bureau on 18 December 2000 (18.12.00);
new claims 8-63 added; remaining claims unchanged (12 pages)]

1. An expandable tubular member, including:
a first tubular section having a first outer diameter;
an intermediate tubular section coupled to the first tubular section having an
intermediate outer diameter; and
5 a second tubular section having a second outer diameter coupled to the
intermediate tubular section having a second outer diameter;
wherein the first and second outer diameters are greater than the intermediate
outer diameter.
- 10 2. A method of fabricating an expandable tubular member, comprising:
providing a tubular member having a first end, a second end, and an
intermediate portion; and
radially expanding the first end and the second end of the tubular member.
- 15 3. An apparatus, comprising:
a tubular member formed by the process of radially expanding an unexpanded
tubular member into contact with an approximately cylindrical passage
using an expansion cone, the unexpanded tubular member including:
a first tubular section having a first outer diameter;
20 an intermediate tubular section coupled to the first tubular
section having an intermediate outer diameter; and
a second tubular section having a second outer diameter coupled
to the intermediate tubular section having a second outer
diameter;
25 wherein the first and second outer diameters are greater than the
intermediate outer diameter.

4. A method of joining a first tubular member to a second tubular member, comprising:

positioning at least a portion of the second tubular member within the first tubular member;

5 radially expanding at least a portion of the second tubular member into contact with the first tubular member; and

radially expanding the first and second tubular members;

wherein the interior diameter of the radially expanded second tubular member is substantially equal to the interior diameter of the radially
10 unexpanded portion of the first tubular member.

5. A tubular member, comprising:

a first tubular member; and

a second tubular member coupled to the first tubular member;

15 wherein the first and second tubular members are coupled by the process of:
positioning at least a portion of the second tubular member within the first tubular member;

radially expanding at least a portion of the second tubular member into contact with the first tubular member; and

20 radially expanding the first and second tubular members;

wherein the interior diameter of the radially expanded second tubular member is substantially equal to an interior diameter of the radially unexpanded portion of the first tubular member.

25

6. A tubular member, comprising:
a first tubular member, including:
an upper portion having an upper wall thickness; and
a lower portion having a lower wall thickness; and
5 a second tubular member coupled to the lower portion of the first tubular member;
wherein the interior diameters of the upper portion of the first tubular member and the second tubular member are substantially equal.
- 10 7. An apparatus, comprising:
a first tubular member;
a second tubular member positioned in overlapping relation to the first tubular member;
an expansion mandrel positioned within the first tubular member including
15 one or more outer surfaces for radially expanding the first and second tubular members;
a support member coupled to the expansion mandrel for supporting the expansion mandrel;
a first fluid conduit positioned within the expansion mandrel and the support
20 member;
a packer sealingly coupled to the first tubular member and slidingly and sealingly coupled to the support member;
a second fluid conduit coupled to the packer; and
a pump fluidically coupled to the second fluid conduit.
25

8. An expansion cone for expanding a tubular member, comprising:
a housing including a tapered first end and a second end;
one or more grooves formed in the outer surface of the tapered first end; and
one or more axial flow passages fluidically coupled to the circumferential
5 grooves.
9. The expansion cone of claim 8, wherein the grooves comprise circumferential
grooves.
- 10 10. The expansion cone of claim 8, wherein the grooves comprise spiral grooves.
11. The expansion cone of claim 8, wherein the grooves are concentrated around
the axial midpoint of the tapered portion of the housing.
- 15 12. The expansion cone of claim 8, wherein the axial flow passages comprise axial
grooves.
13. The expansion cone of claim 12, wherein the axial grooves are spaced apart by
at least about 3 inches in the circumferential direction.
- 20 14. The expansion cone of claim 12, wherein the axial grooves extend from the
tapered first end of the body to the grooves.
15. The expansion cone of claim 12, wherein the axial grooves extend from the
25 second end of the body to the grooves.
16. The expansion cone of claim 12, wherein the axial grooves extend from the
tapered first end of the body to the second end of the body.

17. The expansion cone of claim 8, wherein the flow passages are positioned within the housing of the expansion cone.

18. The expansion cone of claim 17, wherein the flow passages extend from the tapered first end of the body to the grooves.

19. The expansion cone of claim 17, wherein the flow passages extend from the tapered first end of the body to the second end of the body.

20. The expansion cone of claim 19, wherein the flow passages extend from the second end of the body to the grooves.

21. The expansion cone of claim 19, wherein one or more of the flow passages include inserts having restricted flow passages.

22. The expansion cone of claim 19, wherein one or more of the flow passages include filters.

23. The expansion cone of claim 8, wherein the cross sectional area of the grooves is greater than the cross sectional area of the axial flow passages.

24. The expansion cone of claim 8, wherein the cross-sectional area of the grooves ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$.

25. The expansion cone of claim 8, wherein the cross-sectional area of the axial flow passages ranges from about $2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$.

26. The expansion cone of claim 8, wherein the angle of attack of the first tapered end of the body ranges from about 10 to 30 degrees.

27. The expansion cone of claim 8, wherein the grooves are concentrated in a trailing edge portion of the tapered first end.
28. The expansion cone of claim 8, wherein the angle of inclination of the axial
5 flow passages relative to the longitudinal axis of the expansion cone is greater than the angle of attack of the first tapered end.
29. The expansion cone of claim 8, wherein the grooves include:
a flow channel having a first radius of curvature;
10 a first shoulder positioned on one side of the flow channel having a second radius of curvature; and
a second shoulder positioned on the other side of the flow channel having a third radius of curvature.
- 15 30. The expansion cone of claim 29, wherein the first, second and third radii of curvature are substantially equal.
31. The expansion cone of claim 8, wherein the axial flow passages include:
a flow channel having a first radius of curvature;
20 a first shoulder positioned on one side of the flow channel having a second radius of curvature; and
a second shoulder positioned on the other side of the flow channel having a third radius of curvature.
- 25 32. The expansion cone of claim 31, wherein the first, second and third radii of curvature are substantially equal.
33. The expansion cone of claim 31, wherein the second radius of curvature is greater than the third radius of curvature.

34. A method of lubricating the interface between a tubular member and an expansion cone having a first tapered end and a second end during the radial expansion of the tubular member by the expansion cone, wherein the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge portion, comprising:
5 injecting a lubricating fluid into the trailing edge portion.
35. The method of claim 34, wherein the lubricating fluid has a viscosity ranging from about 1 to 10,000 centipoise.
10
36. The method of claim 34, wherein the injecting includes:
injecting lubricating fluid into the first tapered end of the expansion cone.
37. The method of claim 36, wherein the injecting includes:
15 injecting lubricating fluid into the area around the axial midpoint of the first tapered end of the expansion cone.
38. The method of claim 34, wherein the injecting includes:
injecting lubricating fluid into the second end of the expansion cone.
20
39. The method of claim 34, wherein the injecting includes:
injecting lubricating fluid into the tapered first end and the second end of the expansion cone.
40. The method of claim 34, wherein the injecting includes:
25 injecting lubricating fluid into the interior of the expansion cone.
41. The method of claim 34, wherein the injecting includes:
injecting lubricating fluid through the outer surface of the expansion cone.

42. The method of claim 34, wherein the injecting includes:
injecting the lubricating fluid into a plurality of discrete locations along the
trailing edge portion.
- 5 43. The method of claim 34, wherein the lubricating fluid comprises:
drilling mud.
44. The method of claim 42, wherein the lubricating fluid further includes:
TorqTrim III;
10 EP Mudlib; and
DrillN-Slid.
45. The method of claim 34, wherein the lubricating fluid comprises:
TorqTrim III;
15 EP Mudlib; and
DrillN-Slid.
46. A method of removing debris formed during the radial expansion of a tubular
member by an expansion cone from the interface between the tubular member and
20 the expansion cone, the expansion cone including a first tapered end and a second
end, the interface between the tubular member and the first tapered end of the
expansion cone includes a leading edge portion and a trailing edge portion,
comprising:
injecting a lubricating fluid into the interface between the tubular member and
25 the expansion cone.
47. The method of claim 46, wherein the lubricating fluid has a viscosity ranging
from about 1 to 10,000 centipoise.

48. The method of claim 46, wherein the injecting includes:
injecting lubricating fluid into the first tapered end of the expansion cone.
- 5 49. The method of claim 48, wherein the injecting includes:
injecting lubricating fluid into the area around the axial midpoint of the first
tapered end of the expansion cone.
- 10 50. The method of claim 46, wherein the injecting includes:
injecting lubricating fluid into the second end of the expansion cone.
51. The method of claim 46, wherein the injecting includes:
injecting lubricating fluid into the tapered first end and the second end of the
expansion cone.
- 15 52. The method of claim 46, wherein the injecting includes:
injecting lubricating fluid into the interior of the expansion cone.
53. The method of claim 46, wherein the injecting includes:
injecting lubricating fluid through the outer surface of the expansion cone.
- 20 54. The method of claim 46, wherein the lubricating fluid comprises:
drilling mud.
- 25 55. The method of claim 54, wherein the lubricating fluid further includes:
TorqTrim III;
EP Mudlib; and
DrillIN-Slid.

56. The method of claim 46, wherein the lubricating fluid comprises:

TorqTrim III;

EP Mudlib; and

DrillN-Slid.

5

57. A tubular member, comprising:

an annular member, including:

a wall thickness that varies less than about 8 %;

a hoop yield strength that varies less than about 10 %;

10 imperfections of less than about 8 % of the wall thickness;

no failure for radial expansions of up to about 30 %; and

no necking of the walls of the annular member for radial expansions of
up to about 25%.

15

58. A wellbore casing, comprising:

one or more tubular members, each tubular member including:

an annular member, including:

a wall thickness that varies less than about 8 %;

a hoop yield strength that varies less than about 10 %;

20 imperfections of less than about 8 % of the wall thickness;

no failure for radial expansions of up to about 30 %; and

no necking of the walls of the annular member for radial expansions of
up to about 25%.

25

59. A method of forming a wellbore casing, comprising:
placing a tubular member and an expansion cone in a wellbore; and
displacing the expansion cone relative to the tubular member;
wherein the tubular member includes:
5 an annular member, including:
a wall thickness that varies less than about 8 %;
a hoop yield strength that varies less than about 10 %;
imperfections of less than about 8 % of the wall thickness;
no failure for radial expansions of up to about 30 %; and
10 no necking of the walls of the annular member for radial expansions of
up to about 25%.
60. A method of selecting a group of tubular members for subsequent radial
expansion, comprising:
15 radially expanding the ends of a representative sample of the group of tubular
members;
measuring the amount of necking of the walls of the radially expanded ends of
the tubular members; and
if the radially expanded ends of the tubular members do not exhibit necking
20 for radial expansions of up to about 25%, then accepting the group of
tubular members.
61. A method of selecting a group of tubular members, comprising:
radially expanding the ends of a representative sample of the group of tubular
25 members until each of the tubular members fail;
if the radially expanded ends of the tubular members do not fail for radial
expansions of up to about 30%, then accepting the group of tubular
members.

62. A method of inserting a tubular member into a wellbore, comprising:
injecting a lubricating fluid into the wellbore; and
inserting the tubular member into the wellbore.
- 5 63. The method of claim 32, wherein the lubricating fluid comprises:
BARO-LUB GOLD-SEAL™ brand drilling mud lubricant.

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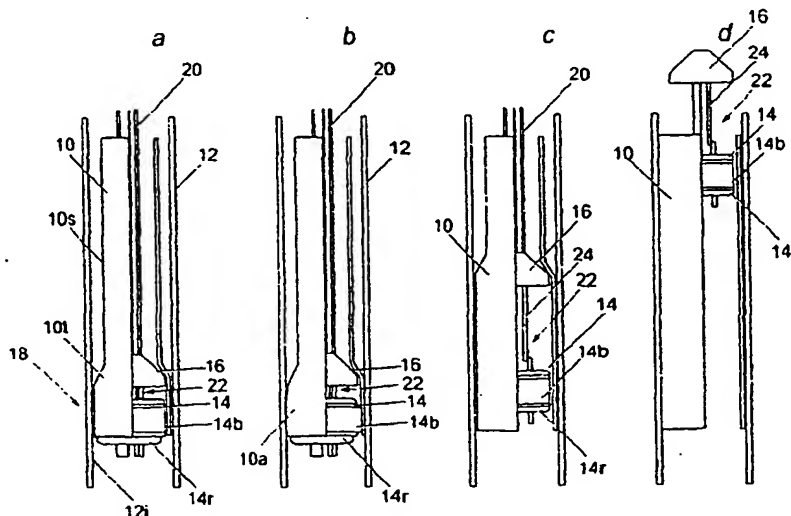
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(54) Title: APPARATUS FOR AND METHOD OF ANCHORING A FIRST CONDUIT TO A SECOND CONDUIT



(57) Abstract: Apparatus and methods are disclosed for anchoring a first conduit (10) to a second conduit (12). The first conduit (10) is typically an expandable conduit whereby a portion of the first conduit is expanded by applying a radial force thereto to provide an anchor and/or seal between the first (10) and second (12) conduits. An inflatable device (14) is provided that can be used to provide a temporary anchor whilst the first (expandable) conduit (10) is radially expanded. An expander device (16) that is capable of applying a radial expansion force to the first conduit (10) is optionally attached to the inflatable device (14).

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1 "Apparatus for and Method of Anchoring a First Conduit
2 to a Second Conduit"

3

4 The present invention relates to an apparatus for and a
5 method of anchoring a first conduit to a second
6 conduit, the apparatus and method particularly, but not
7 exclusively, using an inflatable device to provide a
8 temporary anchor.

9

10 A borehole is conventionally drilled during the
11 recovery of hydrocarbons from a well, the borehole
12 typically being lined with a casing. Casings are
13 installed to prevent the formation around the borehole
14 from collapsing. In addition, casings prevent unwanted
15 fluids from the surrounding formation from flowing into
16 the borehole, and similarly, prevents fluids from
17 within the borehole escaping into the surrounding
18 formation.

19

1 Boreholes are conventionally drilled and cased in a
2 cascaded manner; that is, casing of the borehole begins
3 at the top of the well with a relatively large outer
4 diameter casing. Subsequent casing of a smaller
5 diameter is passed through the inner diameter of the
6 casing above, and thus the outer diameter of the
7 subsequent casing is limited by the inner diameter of
8 the preceding casing. Thus, the casings are cascaded
9 with the diameters of the casing lengths reducing as
10 the depth of the well increases. This gradual
11 reduction in diameter results in a relatively small
12 inside diameter casing near the bottom of the well that
13 could limit the amount of hydrocarbons that can be
14 recovered. In addition, the relatively large diameter
15 borehole at the top of the well involves increased
16 costs due to the large drill bits required, heavy
17 equipment for handling the larger casing, and increased
18 volumes of drill fluid that are required.

19

20 Each casing is typically cemented into place by filling
21 cement into an annulus created between the casing and
22 the surrounding formation. A thin slurry cement is
23 pumped down into the casing followed by a rubber plug
24 on top of the cement. Thereafter, drilling fluid is
25 pumped down the casing above the cement that is pushed
26 out of the bottom of the casing and into the annulus.
27 Pumping of drilling fluid is stopped when the plug
28 reaches the bottom of the casing and the wellbore must
29 be left, typically for several hours, whilst the cement
30 dries. This operation requires an increase in rig time
31 due to the cement pumping and hardening process, that
32 can substantially increase production costs.

1
2 It is known to use a pliable casing that can be
3 radially expanded so that an outer surface of the
4 casing contacts the formation around the borehole. The
5 pliable casing undergoes plastic deformation when
6 expanded, typically by passing an expander device, such
7 as a ceramic or steel cone or the like, through the
8 casing. The expander device is propelled along the
9 casing in a similar manner to a pipeline pig and may be
10 pushed (using fluid pressure for example) or pulled
11 (using drill pipe, rods, coiled tubing, a wireline or
12 the like).

13
14 Lengths of expandable casing are coupled together
15 (typically by threaded couplings) to produce a casing
16 string. The casing string is inserted into the
17 borehole in an unexpanded state and is subsequently
18 expanded using the expander device, typically using a
19 substantial force to facilitate the expansion process.
20 However, the unexpanded casing string requires to be
21 anchored either at or near an upper end or a lower end
22 thereof during the expansion process to prevent undue
23 movement. This is because when the casing string is in
24 an unexpanded state, an outer surface of the casing
25 string does not contact the surrounding borehole
26 formation or an inner face of a pre-installed casing or
27 liner (until at least a portion of the casing has been
28 radially expanded), and thus there is no inherent
29 initial anchoring point.

30

31 Slips are conventionally used to temporarily anchor the
32 unexpanded casing to the borehole during the expansion

1 process. Slips are generally wedge-shaped, steel,
2 hinged portion that provide a temporary anchor when
3 used. Slips are actuated whereby the wedge-shaped
4 portions engage with the surrounding borehole formation
5 or a casing or liner.

6
7 However, the mechanical configuration of slips often
8 causes damage to the casing or liner. In some cases,
9 the damage causes the slip to fail due to a loss of
10 mechanical grip. Slip-type devices in open-hole
11 engaging formation are often prone to slippage also.

12
13 According to a first aspect of the present invention,
14 there is provided an apparatus for anchoring a first
15 conduit to a second conduit, the apparatus comprising
16 an inflatable device for engaging with the first
17 conduit, wherein the inflatable device is inflatable to
18 facilitate anchoring of the first conduit to the second
19 conduit.

20
21 According to a second aspect of the present invention,
22 there is provided a method of anchoring a first conduit
23 to a second conduit, the method comprising the steps of
24 providing a first conduit, providing an inflatable
25 device in contact with the first conduit, running the
26 first conduit and inflatable device into the second
27 conduit, and subsequently inflating the inflatable
28 device to facilitate anchoring of the first conduit to
29 the second conduit.

30
31 According to a third aspect of the present invention,
32 there is provided a method of anchoring an expandable

1 conduit to a second conduit, the method comprising the
2 steps of providing an expandable conduit, running the
3 first conduit into the second conduit, passing an
4 inflatable device into the conduit, and subsequently
5 inflating the inflatable device to facilitate anchoring
6 of the expandable conduit to the second conduit.

7
8 The first conduit is typically an expandable conduit.

9
10 The first or expandable conduit may comprise any type
11 of expandable conduit that is capable of sustaining
12 plastic and/or elastic deformation. The first conduit
13 typically comprises an expandable liner, casing or the
14 like. The second conduit may comprise any type of
15 conduit. The second conduit typically comprises a
16 liner, casing, borehole or the like.

17
18 The inflatable device typically comprises an inflatable
19 balloon-type portion coupled to a ring. This allows a
20 string or the like to be passed through the inflatable
21 device in use.

22
23 Optionally, the inflatable device includes an expander
24 device. The expander device is optionally
25 telescopically coupled to the inflatable device, so
26 that when the expander device is moved a certain
27 distance, the inflatable device is deflated and
28 subsequently moves with the expander device.

29
30 Alternatively, the expandable device may be releasably
31 attached to the inflatable device, typically using a
32 latch mechanism.

1

2 The inflatable device may be located within the
3 expandable conduit. Alternatively, the inflatable
4 device may be coupled at or near an upper end of the
5 expandable conduit, or at or near a lower end of the
6 expandable conduit. The inflatable device may be
7 coupled to the expandable conduit using any suitable
8 connection.

9

10 The inflatable device is typically inflated to expand
11 the expandable conduit whereby the expandable conduit
12 contacts the second conduit, thereby providing an
13 anchor. In this embodiment, the expandable conduit is
14 optionally provided with a slotted portion to
15 facilitate expansion. This is advantageous as the
16 contact between the expandable conduit and the second
17 conduit provides the anchor, and forces applied to the
18 expandable conduit are mainly channelled into the
19 second conduit via the expandable conduit and not the
20 inflatable device.

21

22 Alternatively, the inflatable device is inflated
23 whereby a portion thereof directly contacts the second
24 conduit to provide an anchor.

25

26 The expander device is typically manufactured from
27 steel. Alternatively, the expander device may be
28 manufactured from ceramic, or a combination of steel
29 and ceramic. The expander device is optionally
30 flexible.

31

1 The expander device is optionally provided with at
2 least one seal. The seal typically comprises at least
3 one O-ring.

4
5 The method optionally comprises one, some or all of the
6 additional steps of inserting an expander device into
7 the expandable conduit, operating the expander device
8 to expand the expandable conduit, deflating the
9 inflatable device, and removing the expander device
10 and/or the inflatable device from the expandable
11 conduit and/or the second conduit.

12
13 The method optionally comprises one, some or all of the
14 additional steps of attaching an expander device to the
15 inflatable device, operating the expander device to
16 expand the expandable conduit, re-attaching the
17 expander device to the inflatable device, deflating the
18 inflatable device, and removing the expander device
19 and/or the inflatable device from the expandable
20 conduit and/or second conduit.

21
22 The expander device is typically operated by propelling
23 it through the expandable conduit using fluid pressure.
24 Alternatively, the expander device may be operated by
25 pigging it along the expandable conduit using a
26 conventional pig or tractor. The expander device may
27 also be operated by propelling it using a weight (from
28 the string for example), or may be pulling it through
29 the expandable conduit (e.g. using drill pipe, rods,
30 coiled tubing, a wireline or the like).

31

1 Optionally, the inflatable device may act as a seal
2 whereby fluid pressure can be applied below the seal.

3

4 Embodiments of the present invention shall now be
5 described, by way of example only, with reference to
6 the accompanying drawings, in which:-

7 Figs 1a to 1d are successive stages in anchoring
8 and expanding an expandable conduit within a
9 second conduit using a first embodiment of an
10 inflatable device;

11 Figs 2a to 2d are successive stages in anchoring
12 and expanding an expandable conduit within a
13 borehole to tie back the expandable conduit to a
14 casing using a second embodiment of an inflatable
15 device;

16 Figs 3a to 3d are successive stages in anchoring
17 and expanding an expandable conduit within a
18 second conduit using a third embodiment of an
19 inflatable device;

20 Fig. 4a is a front elevation showing a first
21 configuration of a friction and/or sealing
22 material that can be applied to an outer surface
23 of the conduits shown in Figs 1 to 3;

24 Fig. 4b is an end elevation of the friction and/or
25 sealing material of Fig. 4a;

26 Fig. 4c is an enlarged view of a portion of the
27 material of Figs 4a and 4b showing a profiled
28 outer surface;

29 Fig. 5 is a schematic cross-section of an
30 expandable conduit that can be used with the
31 present invention having an alternative

1 configuration of a friction and/or sealing
2 material;
3 Fig. 6a is an front elevation of the friction
4 and/or sealing material of Fig. 5; and
5 Fig. 6b is an end elevation of the friction and/or
6 sealing material of Fig. 6a.

7
8 Referring to Fig. 1, there is shown in sequence (Figs
9 1a to 1d) successive stages of anchoring an expandable
10 conduit 10 to a casing 12 provided in a borehole (not
11 shown), the borehole typically being drilled to
12 facilitate the recovery of hydrocarbons. The
13 expandable conduit 10 is typically an expandable liner
14 or casing, but any type of expandable conduit may be
15 used.

16
17 The borehole is conventionally lined with casing 12 to
18 prevent the formation around the borehole from
19 collapsing and also to prevent unwanted fluids from the
20 surrounding formation from flowing into the borehole,
21 and similarly, prevents fluids from within the borehole
22 escaping into the surrounding formation. It should be
23 noted that the casing 12 may comprise any type of
24 conduit, such as a pipeline, a liner, a casing, a
25 borehole or the like.

26
27 An inflatable device 14, that in this embodiment has an
28 expander device 16 telescopically attached thereto, is
29 positioned within the expandable conduit 10 before the
30 conduit 10 is inserted into the casing 12.

31

1 Referring to Fig. 1a, the conduit 10 with the
2 inflatable device 14 and expander device 16 located
3 therein is run into the hole to the required setting
4 depth. As can be seen in Fig. 1a, a lower end 101 of
5 the expandable conduit 10 is radially expanded
6 (indicated generally at 18) to allow the inflatable
7 device 14 and the expander device 16 to be located
8 therein. It will be appreciated that although Figs 1a
9 to 1d show the inflatable device 14 and expander device
10 16 located at or near the lower end 101 of the conduit
11 10, the inflatable device 14 and/or the expander device
12 16 may also be located at or near an upper end of the
13 conduit 10. In this case, the expander device 16 is
14 propelled downwardly using, for example, the weight of
15 a string, fluid pressure or any other conventional
16 method.

17

18 The inflatable device 14 may be of any suitable
19 configuration, but is typically a device that has an
20 inflatable annular balloon-type portion 14b that is
21 mounted on an annular ring 14r. The annular ring 14r
22 allows a string, wireline or the like to be passed
23 through the inflatable device 14 as required. This is
24 particularly advantageous where the inflatable device
25 14 is positioned at the upper end of the conduit 10.
26 Thus, substantially full-bore access is still possible.

27

28 Referring to Fig. 1b, the inflatable device 14 is
29 inflated to expand the inflatable annular balloon-type
30 portion 14b. As the balloon-type portion 14b expands,
31 an anchor portion 10a of the conduit 10 is also
32 expanded. The anchor portion 10a is expanded by the

1 inflatable device 14 until it contacts the casing 12,
2 as shown in Fig. 1b. This contact between the anchor
3 portion 10a of the expandable conduit 10 and casing 12
4 provides an anchor point and/or a seal between the
5 expandable conduit 10 and the casing 12. The outer
6 surface of the anchor portion 10a may be suitably
7 profiled (e.g. ribbed) or coated with a friction and/or
8 sealing material 100 (Figs 4a to 4c) to enhance the
9 grip of the conduit 10 on the casing 12. The friction
10 and/or sealing material 100 may comprise, for example,
11 any suitable type of rubber or other resilient
12 materials. It should be noted that the friction and/or
13 sealing material 100 can be provided on an outer
14 surface 10s of the conduit 10 at various axially
15 spaced-apart locations.

16

17 Referring to Figs 4a to 4c, the friction and/or sealing
18 material 100 typically comprises first and second bands
19 102, 104 that are axially spaced apart along a
20 longitudinal axis of the conduit 12. The first and
21 second bands 102, 104 are typically axially spaced by
22 some distance, for example 3 inches (approximately
23 76mm).

24

25 The first and second bands 102, 104 are preferably
26 annular bands that extend circumferentially around the
27 anchor point 10a of the conduit 10, although this
28 configuration is not essential. The first and second
29 bands 102, 104 typically comprise 1 inch wide
30 (approximately 25.4mm) bands of a first type of rubber.
31 The friction and/or sealing material 100 need not
32 extend around the full circumference of the conduit 10.

1
2 Located between the first and second bands 102, 104 is
3 a third band 106 of a second type of rubber. The third
4 band 106 preferably extends between the first and
5 second bands 102, 104 and is thus typically 3 inches
6 (approximately 76mm) wide.

7
8 The first and second bands 102, 104 are typically of a
9 first depth. The third band 106 is typically of a
10 second depth. The first depth is optionally larger
11 than the second depth, although they are typically the
12 same, as shown in Fig. 4a. The first and second bands
13 102, 104 may protrude further from the surface 10s than
14 the third band 106, although this is not essential.

15
16 The first type of rubber (i.e. first and second bands
17 102, 104) is preferably of a harder consistency than
18 the second type of rubber (i.e. third band 106). The
19 first type of rubber is typically 90 durometer rubber,
20 whereas the second type of rubber is typically 60
21 durometer rubber. Durometer is a conventional hardness
22 scale for rubber.

23
24 The particular properties of the rubber may be of any
25 suitable type and the hardnesses quoted are exemplary
26 only. It should also be noted that the relative
27 dimensions and spacings of the first, second and third
28 bands 102, 104, 106 are exemplary only and may be of
29 any suitable dimensions and spacing.

30
31 As can be seen from Fig. 4c in particular, an outer
32 face 106s of the third band 106 can be profiled. The

1 outer face 106s is ribbed to enhance the grip of the
2 third band 106 on an inner face 12i of the casing 12.
3 It will be appreciated that an outer surface on the
4 first and second bands 102, 104 may also be profiled
5 (e.g. ribbed).
6

7 The two outer bands 102, 104 being of a harder rubber
8 provide a relatively high temperature seal and a back-
9 up seal to the relatively softer rubber of the third
10 band 106. The third band 106 typically provides a
11 lower temperature seal.
12

13 Referring to Fig. 5, there is shown an alternative
14 conduit 120 that can be used in place of conduit 10.
15 Conduit 120 is substantially the same as conduit 10,
16 but is provided with a different configuration of
17 friction and/or sealing material 122 on an outer
18 surface 120s.
19

20 The expandable conduit 120 is provided with a pre-
21 expanded portion 120e in which an expander device (e.g.
22 expander device 16) and/or an inflatable device (e.g.
23 device 14) may be located whilst the conduit 120 is run
24 into a borehole or the like. It should be noted that
25 the expander device need not be located in the conduit
26 120 whilst it is being run into the borehole; and can
27 be located in the conduit 120 once it is in place.
28

29 As shown in Fig. 5, the expandable conduit 100 is
30 provided with the friction and/or sealing material 122
31 at at least one location. The fiction and/or sealing
32 material 122 is applied to the outer surface 120s of

1 the conduit 120 at axially spaced apart locations,
2 typically spaced from one another by around 12 inches
3 (approximately 305mm).

4

5 The friction and/or sealing material 122 is best shown
6 in Figs 6a and 6b. The friction and/or sealing
7 material 122 is in the form of a zigzag. In this
8 embodiment, the friction and/or sealing material 122
9 comprises a single (preferably annular) band of rubber
10 that is, for example, of 90 durometers hardness and is
11 about 2.5 inches (approximately 28mm) wide by around
12 0.12 inches (approximately 3mm) deep.

13

14 To provide a zigzag pattern and hence increase the
15 strength of the grip and/or seal that the formation 150
16 provides in use, a number of slots 124a, 124b (e.g. 20)
17 are milled into the band of rubber. The slots 124a,
18 124b are typically in the order of 0.2 inches
19 (approximately 5mm) wide by around 2 inches
20 (approximately 50mm) long.

21

22 To create the zigzag pattern, the slots 124a are milled
23 at around 20 circumferentially spaced-apart locations,
24 with around 18° between each along one edge 122a of the
25 band. The process is then repeated by milling another
26 20 slots 124b on the other side 122b of the band, the
27 slots 124b on side 122b being circumferentially offset
28 by 9° from the slots 124a on the other side 122a.

29

30 In use, the friction and/or sealing material 122 is
31 applied to the outer surface 120s of the (unexpanded)
32 expandable conduit 120. It should be noted that the

1 configuration, number and spacing of the friction
2 and/or sealing material 122 can be chosen to suit the
3 particular application.

4
5 It should be noted that forces applied to the conduit
6 10, 120 e.g. by subsequent movement of the conduit 10,
7 120 that is by pushing or pulling on the conduit 10,
8 120 for example, will be mainly transferred to the
9 casing 12 via the anchor point and not through the
10 inflatable device 14. This is advantageous as it
11 reduces the risk of damage to the inflatable device 14.
12 Additionally, this also reduces the risk of damage to
13 the casing 12 that may have occurred where a
14 conventional slip is used. Also, conventional slips
15 may lose their grip on the casing 12 where damage
16 ensues or the casing 12 is weak. Transferring
17 substantially all of the forces directly to the casing
18 12 via the anchor point obviates these disadvantages.

19
20 The expander device 16 can then be pulled through the
21 expandable conduit 10, 120 to radially expand the
22 conduit 10, 120 as shown in Fig. 1c. The expander
23 device 16 can be propelled through the conduit 10, 120
24 in any conventional manner. In Fig. 1, the expander
25 device 16 is pulled through the conduit 10, 120 using a
26 string 20 that is attached to the expander device 16 in
27 any conventional manner.

28
29 In the embodiment shown in Fig. 1, the expander device
30 16 is telescopically coupled to the inflatable device
31 14 using a telescopic coupling, generally indicated at
32 22. Coupling 22 comprises one or more telescopically

1 coupled members 24 that are attached to the inflatable
2 device 14. As the expander device 16 is pulled
3 upwards, the telescopic coupling 22 extends a certain
4 distance, say 10 feet (approximately 3 metres), at
5 which point the telescopic member(s) 24 are fully
6 extended. At this point, the inflatable balloon-type
7 portion 14b is automatically deflated and further
8 upward movement of the expander device 16 causes the
9 inflatable device 14 also to move upward, as shown in
10 Fig. 1d.

11
12 It should be noted that the inflatable device 14 is no
13 longer required to anchor the conduit 10, 120 to the
14 casing 12 as the expanded conduit 10 (Figs 1c and 1d)
15 secure the (expanded and unexpanded) conduit 10, 120 to
16 the casing 12. The friction and/or sealing material
17 100, 122 is used to enhance the grip of the conduit 10,
18 120 on the casing 12 in use, and can also provide a
19 seal in an annulus created between the conduit 10, 120
20 and the casing 12.

21
22 The expander device 16 is continually pulled upwards
23 towards the surface until the expandable conduit 10,
24 120 is fully expanded to contact the casing 12.
25 Thereafter, the inflatable device 14 and the expander
26 device 16 may be removed from the expandable conduit
27 10, 120 and/or the casing 12 at the surface.

28
29 Anchoring and expanding the expandable conduit 10, 120
30 in this way has several advantages. With the
31 embodiment shown in Fig. 1, it is possible to deploy a
32 control line or coiled tubing to control operation of

1 the inflatable device 14 and any other apparatus
2 located in the borehole, and a control line, wireline
3 or coiled tubing may be used to propel or pull the
4 expander device 16. With the embodiment shown in Fig.
5 1, there is no pressure exposure to the surrounding
6 formation and no rig is required. With the inflatable
7 device 14 configured as an annular ring 14r,
8 substantially full bore access is still possible.

9
10 It should be noted that the method described with
11 reference to Fig. 1 is intended to expand the
12 expandable conduit 10, 120 in a single pass of the
13 expander device 16 through the expandable conduit 10,
14 120, but multiple passes and/or expansions are
15 possible.

16
17 Referring to Fig. 2, there is shown in sequence (Figs
18 2a to 2d) successive stages of hanging an expandable
19 conduit 30 off a casing 32 (ie tying back a liner), the
20 expandable conduit 30 typically comprising an
21 expandable liner and being used to line or case a lower
22 portion of a borehole 34, the borehole 34 typically
23 being drilled to facilitate the recovery of
24 hydrocarbons. The lower portion of the borehole 34 has
25 not been lined/cased, wherein the upper portion of the
26 borehole 34 has been lined with an existing casing or
27 liner 36.

28
29 In the embodiment shown in Fig. 2, the expandable
30 conduit 30 is provided with a friction and/or sealing
31 material 38 on an outer surface thereof. The function
32 of the friction and/or sealing material 38 is to

1 provide a (friction and/or sealing) coupling between
2 the expandable conduit 30 and the existing liner or
3 casing 36. The friction and/or sealing material 38 may
4 also provide a seal between the lower (unlined) and
5 upper (lined) portions of the borehole 34. The
6 friction and/or sealing material may comprise, for
7 example, any suitable type of rubber or other resilient
8 materials. For example, the friction and/or sealing
9 material 38 can be configured in a similar way to the
10 friction and/or sealing material 100, 122 described
11 above with reference to Figs 4 to 6.

12

13 Additionally, the conduit 30 may be provided with
14 friction and/or sealing material (e.g. material 100,
15 122) at a lower end 301 of the conduit 30 to enhance
16 the anchoring effect at this portion of the conduit.
17 Additionally, the friction and/or sealing material can
18 be provided at various spaced-apart locations along the
19 length of the conduit 30 to enhance the coupling
20 between the conduit 30 and the borehole 34 or casing
21 36.

22

23 Referring to Fig. 2, an inflatable device 40, that has
24 an expander device 42 releasably attached thereto, is
25 positioned within the expandable conduit 30 before the
26 conduit 30 is inserted into the borehole 34. The
27 conduit 30 is provided with an expandable portion of
28 casing or liner 44, portion 44 being provided with a
29 plurality of longitudinal slots 48. The portion 44 may
30 be located at a lower end 301 of the conduit 30 or may
31 be integral therewith.

1 Referring to Fig. 2a, the conduit 30 with the
2 inflatable device 40 and expander device 42 releasably
3 attached at or near a lower end thereof, is run into
4 the borehole 34 to the required setting depth. As can
5 be seen in Fig. 2a, a lower end 30l of the conduit 30
6 is radially expanded (indicated generally at 50) to
7 allow the expander device 42 to be located therein. It
8 will be appreciated that although Figs 2a to 2d show
9 the inflatable device 40 and expander device 42 located
10 at or near the lower end 30l of the conduit 30, the
11 inflatable device 40 and/or the expander device 42 may
12 also be located at or near an upper end of the conduit
13 30. In this case, the expander device 42 is propelled
14 downwardly using, for example, the weight of a string,
15 fluid pressure or any other conventional method.

16
17 The inflatable device 40 may be of any suitable
18 configuration, but is typically a device that has an
19 inflatable annular balloon-type portion 40b that is
20 mounted on an annular ring 40r. The annular ring 40r
21 allows a string, wireline or the like to be passed
22 through the inflatable device 40 as required. This is
23 particularly advantageous where the inflatable device
24 40 is positioned at the upper end of the conduit 30.

25
26 Referring to Fig. 2b, the inflatable device 40 is
27 inflated to expand the inflatable annular balloon-type
28 portion 40b. As the balloon-type portion 40b expands,
29 the expandable portion 44 of conduit 30 also expands.
30 As can be seen in Fig. 2b, the longitudinal slots 48
31 widen as the portion 44 expands. Portion 44 acts as an
32 anchor for the casing 30 and is expanded until it

1 contacts the borehole 34, as shown in Fig. 2b. This
2 contact between portion 44 and the borehole 34 provides
3 an anchor point and/or a seal between the expandable
4 conduit 30 (to which portion 44 is attached or integral
5 therewith) and the borehole 34.

6
7 As with the previous embodiment, the expander device 42
8 is then pulled through the expandable conduit 30 to
9 radially expand the conduit 30, as shown in Fig. 2c.
10 The expander device 42 can be propelled through the
11 conduit 30 in any conventional manner. In Fig. 2, the
12 expander device 42 is pulled through the conduit 30
13 using a drill pipe or string 52 that is attached to the
14 expander device 42 in any conventional manner.

15
16 As the expander device 42 is pulled upwards, the upward
17 movement thereof is stopped after a predetermined time
18 or distance, at which point the expander device 42 is
19 lowered until a coupling between the expander device 42
20 and the inflatable device 40 latches. As with the
21 previous embodiments, the inflatable annular balloon-
22 type portion 40b is automatically deflated and further
23 upward movement of the expander device 42 causes the
24 inflatable device 40 also to move upward, as shown in
25 Fig. 2d. It should be noted that the upward movement
26 of the expander device 42 should only be stopped once a
27 sufficient length of conduit 30 has been expanded to
28 provide a sufficient anchor.

29

30 It should also be noted that the portion 44 is no
31 longer required to anchor the conduit 30 to the
32 borehole 34 as the expanded conduit 30 (Figs 2c and 2d)

1 secures the conduit 30 to the borehole 34. The
2 friction and/or sealing material (where used) can help
3 to provide a reliable anchor for the conduit 30 whilst
4 it is being expanded and also when in use.

5

6 The expander device 42 is continually pulled upwards
7 until the conduit 30 is fully expanded, as shown in
8 Fig. 2d. Thereafter, the inflatable device 40 and the
9 expander device 42 may be removed from the expandable
10 conduit 30 and the borehole at the surface. As shown
11 in Fig. 2d, the conduit 30 expands whereby the friction
12 and/or sealing material 38 contacts the casing 36.
13 This provides a tie back to the casing 36 and
14 optionally a seal between the upper (lined) portion of
15 the wellbore and the lower (lined) borehole 34,
16 depending upon the composition of the material 38.

17

18 With the embodiment shown in Fig. 2, there is no
19 pressure exposure to the formation, full bore access is
20 still possible, the conduit 30 may be expanded in a
21 single pass (multiple passes possible) and it may be
22 used to anchor and set in an open hole. Additionally,
23 it provides a tie back to the casing 36 in a single
24 pass of the expander device 42. It should be noted
25 that the method described with reference to Fig. 2 is
26 intended to tie back the casing in a single pass, but
27 multiple passes and/or expansions are possible.

28

29 It should also be noted that successive lengths of
30 expandable conduit may be coupled to casings or liners
31 thereabove using the same method. Thus, the method(s)

1 described herein may be used to line or case a borehole
2 without the use of cement.

3

4 Referring to Fig. 3, there is shown in sequence (Figs
5 3a to 3d) successive stages of anchoring an expandable
6 conduit 80 to a casing 82 provided in a borehole (not
7 shown), the borehole typically being drilled to
8 facilitate the recovery of hydrocarbons.

9

10 An inflatable device 84 is releasably attached to a
11 lower end 801 of the expandable conduit 80 before the
12 conduit 80 is inserted into the casing 82. The
13 expander device 86 is located within the lower end 801
14 of the conduit 80, the lower end 801 being expanded to
15 accommodate the expander device 86. Similar to the
16 previous embodiment, the inflatable device 84 has the
17 expander device 86 releasably coupled thereto via a
18 coupling 88. Otherwise, the inflatable device 84 and
19 the expander device 86 are substantially the same as
20 the previous embodiments.

21

22 Referring to Fig. 3a, the casing 80 with the inflatable
23 device 84 attached thereto and the expander device 86
24 located therein is run into the hole to the required
25 setting depth. It will be appreciated that although
26 Figs 3a to 3d show the inflatable device 84 releasably
27 attached to the lower end 801 of the conduit 80, the
28 inflatable device 84 may be releasably attached at or
29 near an upper end of the conduit 80.

30

31 The inflatable device 84 may be of any suitable
32 configuration, but is typically a device that has an

1 inflatable annular balloon-type portion 84b that is
2 mounted on an annular ring 84r. The annular ring 84r
3 allows a string, wireline or the like to be passed
4 through the inflatable device 84 as required. This is
5 particularly advantageous where the inflatable device
6 84 and/or the expander device 86 are positioned at the
7 upper end of the conduit 80.

8
9 Referring to Fig. 3b, the inflatable device 84 is
10 inflated to expand the inflatable annular balloon-type
11 portion 84b. As the balloon-type portion 84b expands,
12 it contacts the casing 82, thus providing an anchor
13 between the conduit 80 and the casing 82. This contact
14 between the balloon-type portion 84b and the casing 82
15 provides an anchor point and/or a seal between the
16 conduit 80 and the casing 82.

17
18 It should be noted that in this embodiment, the forces
19 applied to the conduit 80 by subsequent movement of the
20 conduit 80, that is by pushing or pulling on the
21 conduit 80 for example, will be transferred to the
22 casing 82 via the inflatable device 84. However,
23 unlike conventional slips, the inflated balloon-type
24 portion 84b is less likely to damage the casing.
25 Additionally, the size of the balloon-type portion 84b
26 can be chosen whereby it is sufficiently large so as
27 not to lose its grip on the casing 82, even when the
28 inflatable device 84 is moved upwardly or downwardly.

29
30 The expander device 86 is pulled through the expandable
31 conduit 80 to radially expand the conduit 80, as shown
32 in Fig. 3c. The expander device 86 can be propelled

1 through the conduit 80 in any conventional manner, as
2 with the previous embodiments.

3

4 Also, and as with the previous embodiments, an outer
5 surface 80s of the conduit 80 can be provided with a
6 friction and/or sealing material. The friction and/or
7 sealing material may comprise, for example, any
8 suitable type of rubber or other resilient materials.
9 For example, the friction and/or sealing material can
10 be configured in a similar way to the friction and/or
11 sealing material 100, 122 described above with
12 reference to Figs 4 to 6.

13

14 Additionally, the conduit 80 may be provided with
15 friction and/or sealing material (e.g. material 100,
16 122) at a lower end 80l of the conduit 80 to enhance
17 the anchoring effect at this portion of the conduit 80.
18 Additionally, the friction and/or sealing material can
19 be provided at various spaced-apart locations along the
20 length of the conduit 80 to enhance the coupling
21 between the conduit 80 and the casing 82.

22

23 As the expander device 86 is pulled upwards, the upward
24 movement thereof is stopped after a predetermined time
25 or distance, at which point the expander device 84 is
26 lowered until the coupling 88 between the expander
27 device 86 and the inflatable device 86 latches. As
28 with the previous embodiments, the inflatable balloon-
29 type portion 84b is automatically deflated and further
30 upward movement of the expander device 86 causes the
31 inflatable device 84 also to move upward, as shown in
32 Fig. 3d. It should be noted that the upward movement

1 of the expander device 86 should only be stopped once a
2 sufficient length of conduit 80 has been expanded to
3 provide a sufficient anchor.

4
5 The expander device 86 is continually pulled upwards
6 towards the surface until the conduit 80 is fully
7 expanded to contact the casing 82. Thereafter, the
8 inflatable device 84 and the expander device 86 may be
9 removed from the borehole at the surface.

10
11 Anchoring and expanding the conduit 80 in this way has
12 the same advantages as in the previous embodiment, but
13 the Fig. 3 embodiment is designed to anchor and set in
14 cased hole rather than open hole.

15
16 The method and apparatus described herein may be used
17 for a plurality of different downhole functions
18 relating to the use of expandable conduit. For
19 example, they may be used where the original liner or
20 casing requires to be repaired due to damage or the
21 like by overlaying the damaged portion with a portion
22 of expandable conduit. They may also be used to tie
23 back to the liner or casing, as described herein.

24
25 Thus, there is provided in certain embodiments an
26 apparatus and method of anchoring an expandable conduit
27 to a second conduit. The apparatus and method of
28 certain embodiments provide numerous advantages over
29 conventional mechanical anchoring devices, such as
30 slips, particularly by reducing the potential damage to
31 conduits that mechanical slips may cause. Certain
32 embodiments of apparatus and methods involve the use of

1 an inflatable device that can either be a) attached
2 directly at or near the top or bottom of the expandable
3 conduit, or b) placed within the top or bottom of the
4 expandable conduit. In a), anchoring forces are
5 generated as a result of friction between the
6 inflatable device and the second conduit, the forces
7 being passed into the conduit via the inflatable
8 device. In b), anchoring forces are generated by
9 friction between an outer surface of the expandable
10 conduit and the second conduit, the forces being
11 substantially passed into the second conduit directly
12 via the expandable conduit. The outer surface of the
13 expandable conduit may be suitably prepared (ie
14 provided with a friction enhancing material) to
15 increase the strength of the anchor.
16
17 Modifications and improvements may be made to the
18 foregoing without departing from the scope of the
19 present invention.

1 CLAIMS

2 1. Apparatus for anchoring a first conduit to a
3 second conduit, the apparatus comprising an inflatable
4 device for engaging with the first conduit, wherein the
5 inflatable device is inflatable to facilitate anchoring
6 of the first conduit to the second conduit.

7

8 2. Apparatus according to claim 1, wherein the first
9 conduit is an expandable conduit.

10

11 3. Apparatus according to claim 1 or claim 2, wherein
12 the first conduit comprises any type of expandable
13 conduit that is capable of sustaining plastic and/or
14 elastic deformation.

15

16 4. Apparatus according to any preceding claim,
17 wherein the first conduit comprises an expandable
18 liner, casing or the like.

19

20 5. Apparatus according to any preceding claim,
21 wherein the second conduit comprises a liner, casing,
22 borehole or the like.

23

24 6. Apparatus according to any preceding claim,
25 wherein the inflatable device comprises an inflatable
26 balloon-type portion coupled to a ring.

27

28 7. Apparatus according to any preceding claim,
29 wherein the inflatable device includes an expander
30 device.

31

1 8. Apparatus according to claim 7, wherein the
2 expander device is telescopically coupled to the
3 inflatable device, so that when the expander device is
4 moved a certain distance, the inflatable device is
5 deflated and subsequently moves with the expander
6 device.

7
8 9. Apparatus according to claim 7, wherein the
9 expander device is releasably attached to the
10 inflatable device.

11
12 10. Apparatus according to claim 9, wherein the
13 expander device is releasably attached to the
14 inflatable device using a latch mechanism.

15
16 11. Apparatus according to any preceding claim,
17 wherein the inflatable device is located within the
18 expandable conduit.

19
20 12. Apparatus according to any one of claims 1 to 11,
21 wherein the inflatable device is coupled at or near an
22 upper end of the expandable conduit, or at or near a
23 lower end of the expandable conduit.

24
25 13. Apparatus according to any preceding claim
26 wherein the inflatable device is inflated to expand the
27 expandable conduit whereby the expandable conduit
28 contacts the second conduit, thereby providing an
29 anchor.

30

1 14. Apparatus according to claim 13, wherein the
2 expandable conduit is provided with a slotted portion
3 to facilitate expansion.

4
5 15. Apparatus according to any one of claims 1 to 12,
6 wherein the inflatable device is inflated whereby a
7 portion thereof directly contacts the second conduit to
8 provide an anchor.

9
10 16. A method of anchoring a first conduit to a second
11 conduit, the method comprising the steps of providing a
12 first conduit, providing an inflatable device in
13 contact with the first conduit, running the first
14 conduit and inflatable device into the second conduit,
15 and subsequently inflating the inflatable device to
16 facilitate anchoring of the first conduit to the second
17 conduit.

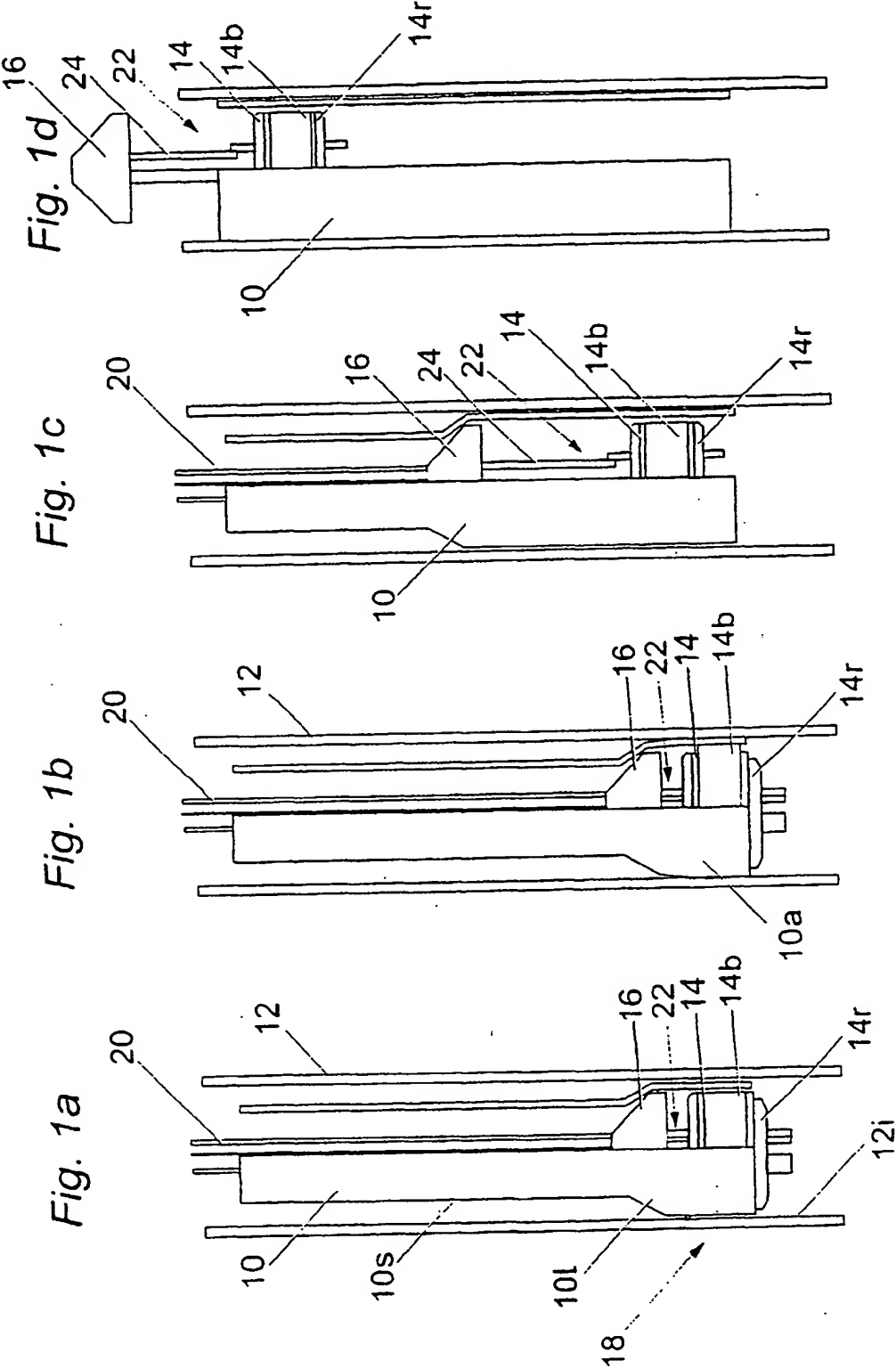
18
19 17. A method of anchoring an expandable conduit to a
20 second conduit, the method comprising the steps of
21 providing an expandable conduit, running the first
22 conduit into the second conduit, passing an inflatable
23 device into the conduit, and subsequently inflating the
24 inflatable device to facilitate anchoring of the
25 expandable conduit to the second conduit.

26
27 18. A method according to claim 16 or claim 17,
28 wherein the method includes one, some or all of the
29 additional steps of inserting an expander device into
30 the expandable conduit, operating the expander device
31 to expand the expandable conduit, deflating the
32 inflatable device, and removing the expander device

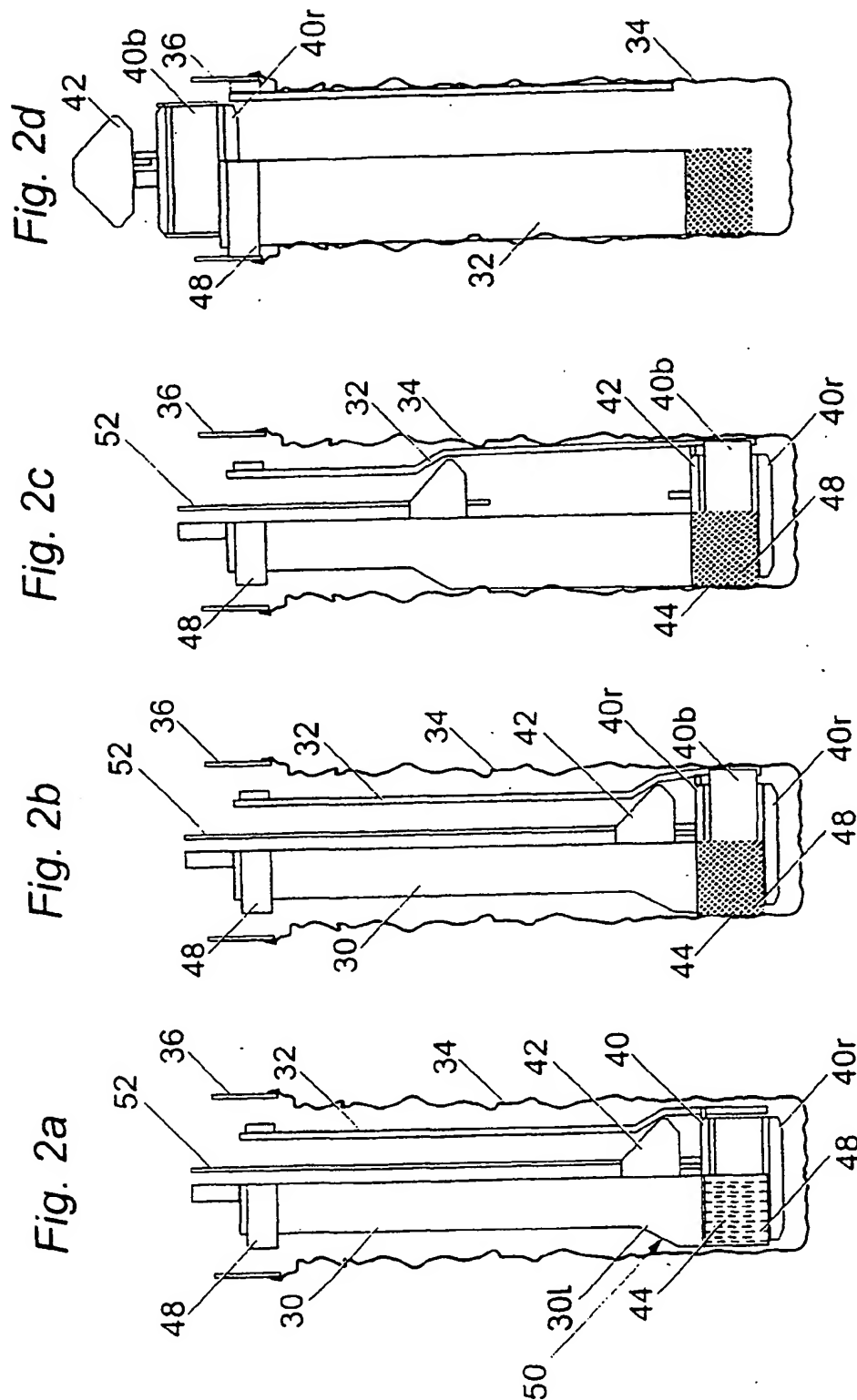
1 and/or the inflatable device from the expandable
2 conduit and/or the second conduit.

3

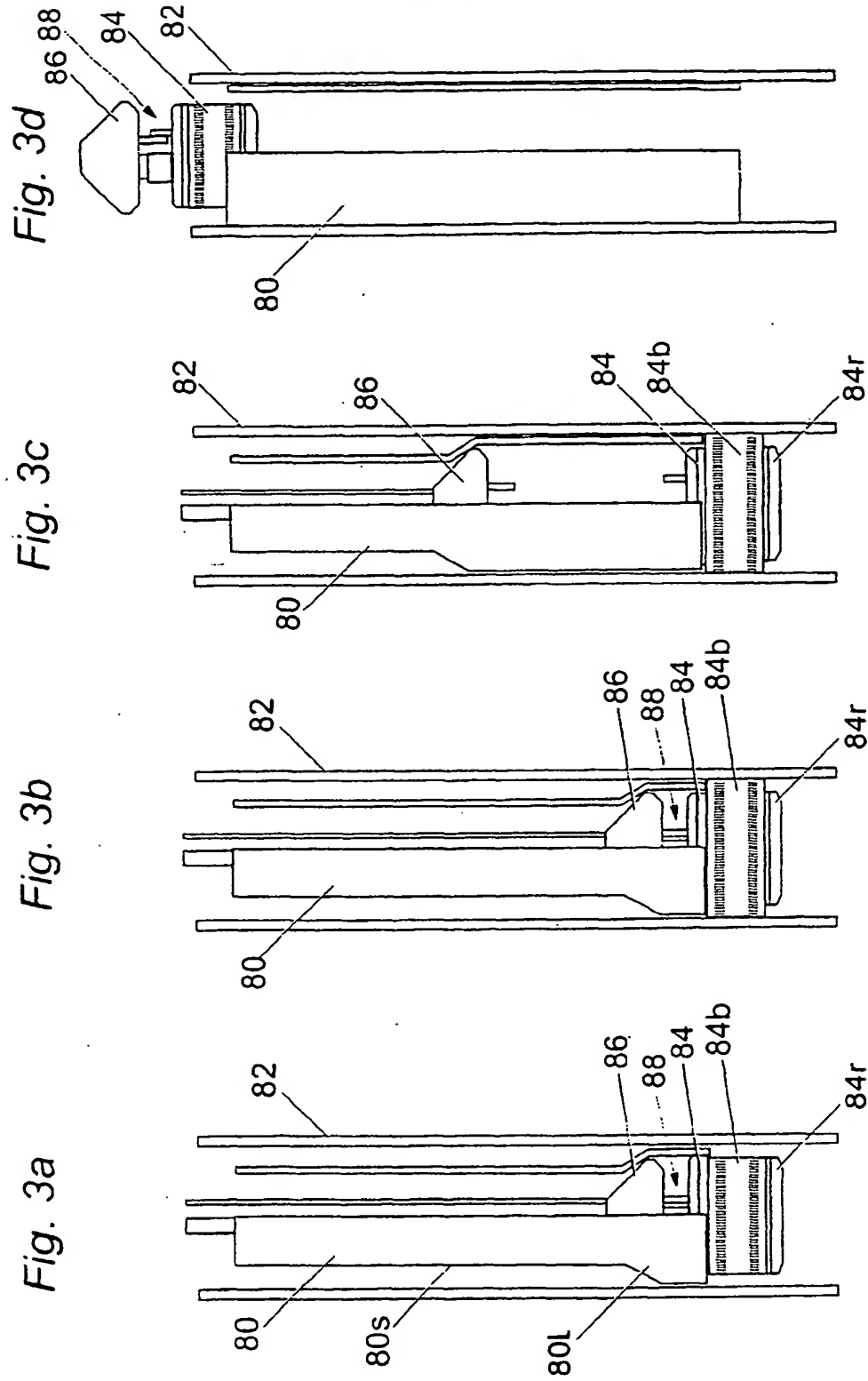
4 19. A method according to any one of claims 16 to 18,
5 wherein the method includes one, some or all of the
6 additional steps of attaching an expander device to the
7 inflatable device, operating the expander device to
8 expand the expandable conduit, re-attaching the
9 expander device to the inflatable device, deflating the
10 inflatable device, and removing the expander device
11 and/or the inflatable device from the expandable
12 conduit and/or second conduit.

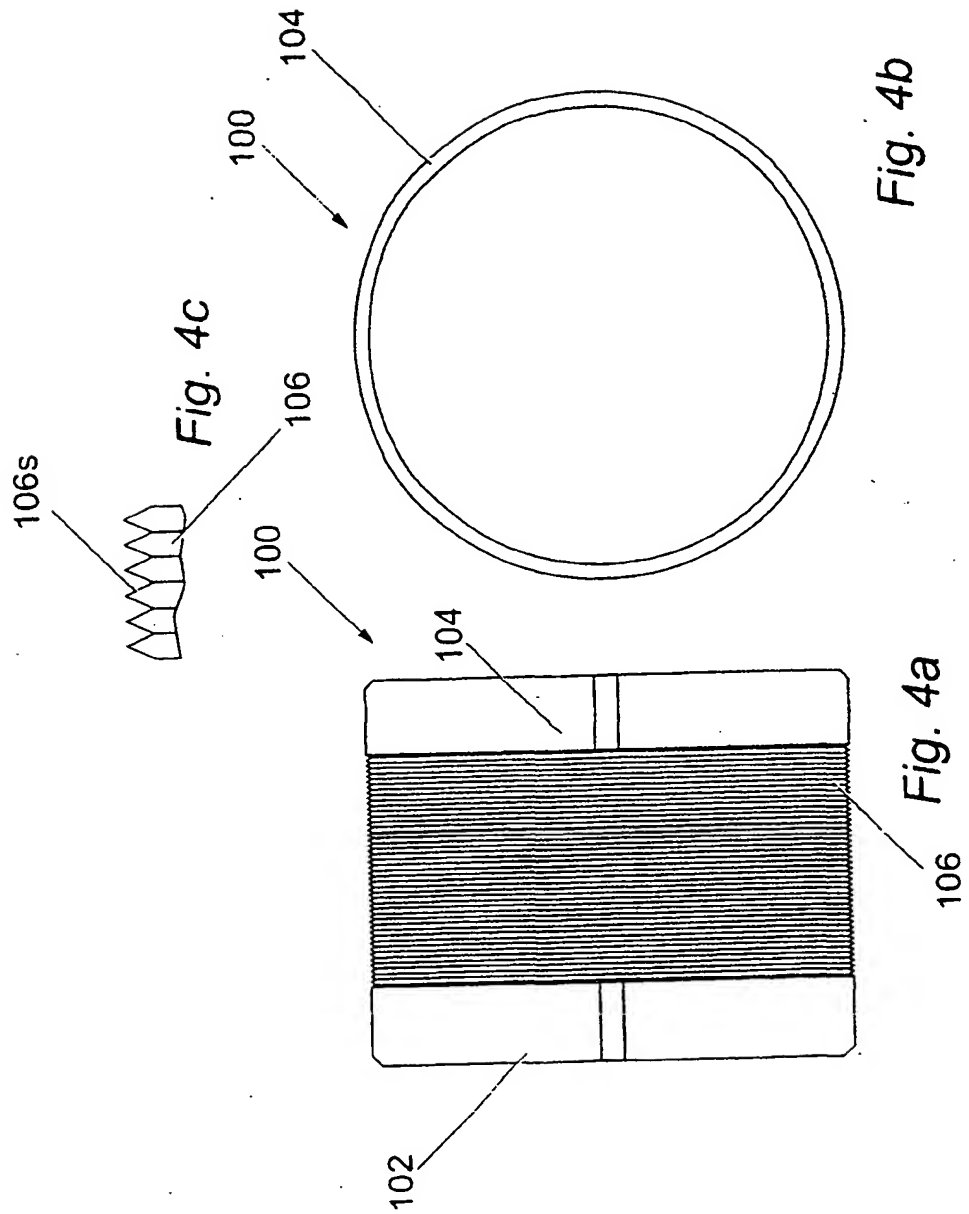


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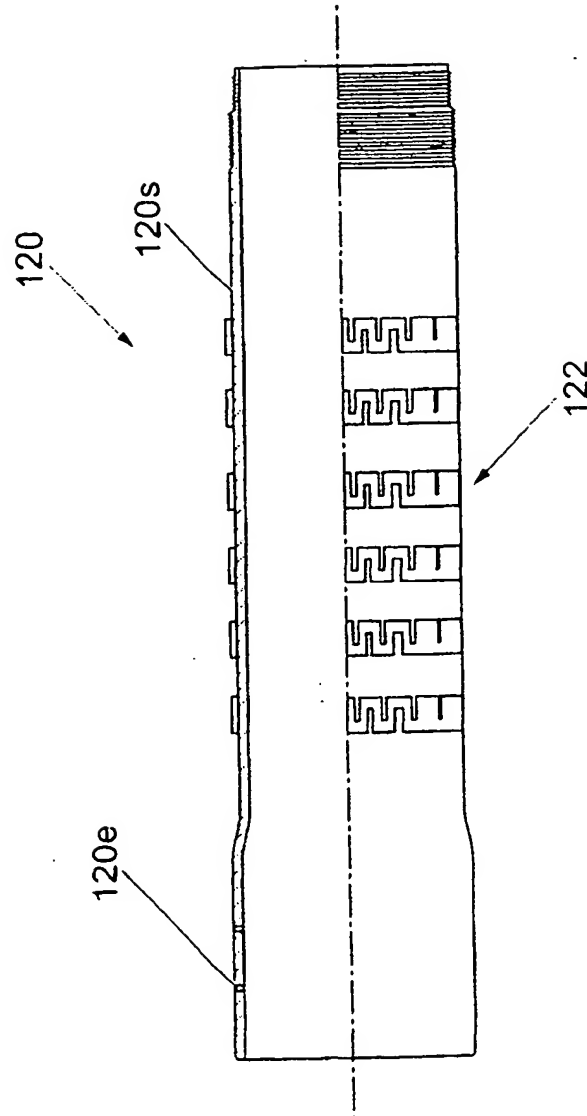


Fig. 5

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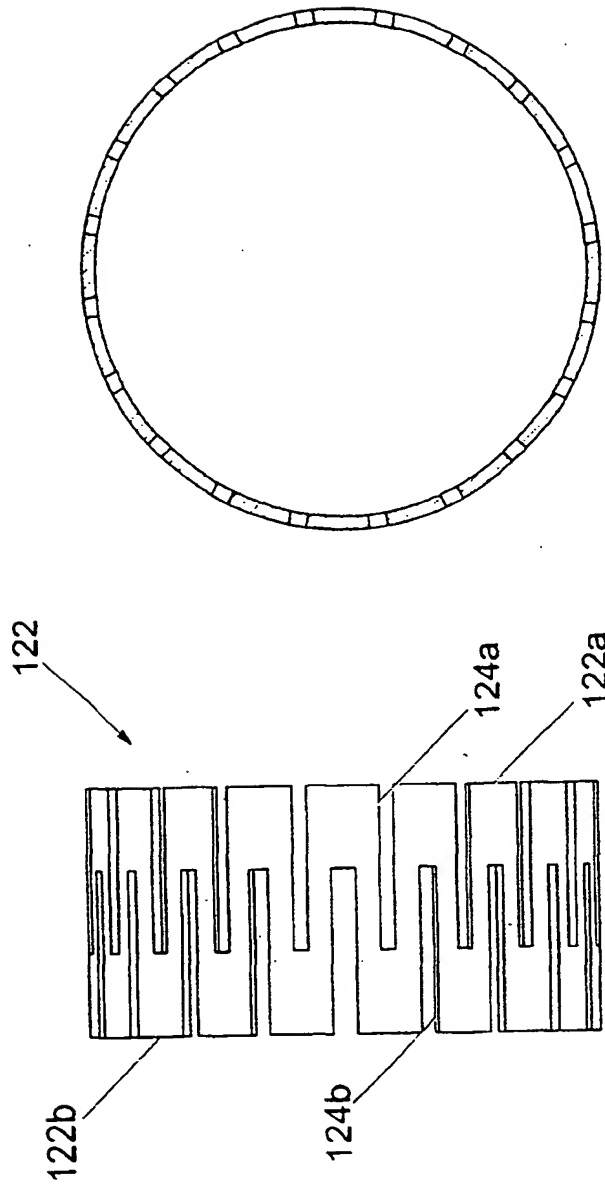


Fig. 6b

Fig. 6a

INTERNATIONAL SEARCH REPORT

Int. Application No
PCT/GB 00/03406

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B43/10

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)
EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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X	EP 0 842 348 A (DRILLFLEX) 20 May 1998 (1998-05-20) the whole document	1-7, 11, 13, 16, 18
A	WO 99 23354 A (METCALFE PAUL DAVID ; PETROLINE WELLSYSTEMS LTD (GB)) 14 May 1999 (1999-05-14) page 8, line 17 - page 9, line 3	1-19
P, A	GB 2 344 606 A (SHELL INT RESEARCH) 14 June 2000 (2000-06-14) abstract; figures 1-11	1-19

☐ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

* Special categories of cited documents:

A document defining the general state of the art which is not considered to be of particular relevance

E earlier document but published on or after the international filing date

L document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

O document referring to an oral disclosure, use, exhibition or other means

P document published prior to the international filing date but later than the priority date claimed

T later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

X document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

Y document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.

S document member of the same patent family

Date of the actual completion of the international search

17 November 2000

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Garrido Garcia, M

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No

PCT/GB 00/03406

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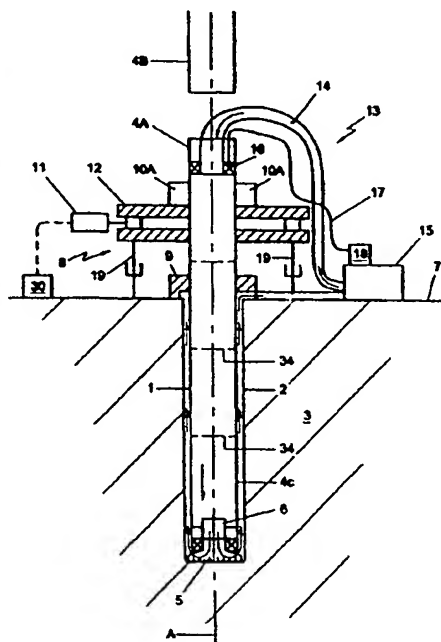
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- (72) Inventor; and
- (73) Inventor/Applicant (for US only): BAKKER, Thomas, Walburga [NL/NL]; Tynaarlosestraat 68, NL-9481 AE Vries (NL).
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- Published:
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[Continued on next page]

(54) Title: METHOD AND DEVICE FOR MOVING A TUBE IN A BOREHOLE IN THE GROUND



(57) Abstract: A method for displacing a tube (1) in a borehole (2) in the ground (3) is disclosed. The tube is simultaneously displaced along and about its axis, such that it is axially introduced into or retracted from the borehole. According to the invention, displacing the composed tube about its axis comprises an oscillating movement. The invention further relates to a device for displacing a tube in a borehole.

WO 01/21929 A1

WEST



For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

Title: Method and device for moving a tube in a borehole in the ground

FIELD AND BACKGROUND OF THE INVENTION

This invention relates to a method for axially moving a tube in a borehole in the ground according to the introductory portion of claim 1. The invention further relates to a device for axially moving a tube into a borehole in the ground according to the introductory portion of claim 19.

Such methods and devices are known from practice, for instance for axially inserting a tube in a borehole or for axially retracting tube from a borehole. Such a tube may be used for the drilling process and simultaneously for the protection of the newly drilled wellbore. This technique is commonly referred to in the field as casing drilling. Such a borehole can be used for extracting oil or gas and for other purposes, such as for the extraction of salt or geothermal energy and also for civil engineering purposes such as laying pipelines under rivers.

When using the known methods and devices, usually a first tube part is inserted into a borehole in the ground provided by a drill. Subsequently further tube parts are coupled to the upper end of the tube reaching into the borehole, e.g. via a screw and/or clamp coupling. As the tube is introduced further into the ground, successive tube parts, which can each be composed of one or more pre-connected tube joints, are connected to the proximal end of the composed section of the tube end projecting from the ground until the tube has reached its final length. When the tube is removed, this method is essentially reversed.

During insertion or retraction the composed tube is driven to rotate about its axis in a fixed direction, such that continuous rotation is achieved. This is done to provide

the frictional force between the tube and its surroundings with a tangential component, thus reducing the axial frictional component, which substantially decreases the axial force needed to insert or retract the composed tube into or
5 from the borehole. It shall be clear that also a single length of tube can be used instead of connected tube parts.

A disadvantage of the known method and device for axially moving a tube in this manner is that, due to the continuous rotation of the tube, it is a problem to provide
10 solid-state, safe connections between the stationary ground and apparatuses rotating jointly or solidarily with the tube. In particular, during drilling operations a swivel connecting the tube to a mud supply is to be provided with an elaborate rotational seal. The same holds true for e.g. hydraulic
15 connections to a drill carried on the tube or pneumatic connections to a packer connected to the tube. In particular, providing a spark-free electrical connection between devices rotating substantially jointly with the tube and the ground in the often explosion endangered environment near a borehole
20 has proven to be a problem.

In practice, due to the problem of providing a reliable connection, often the rotation is stopped, when e.g. a drill needs to be retracted or when an inspection apparatus has to be lowered. This greatly increases the risk of the
25 tube getting stuck due to settling of the ground or due to a phenomenon known in the field as differential sticking.

In the currently known art of casing drilling, the direction of the tube is controlled by devices protruding from the lower end of the tube. The application of such
30 devices is costly and the measure of control is limited. As such it is currently not feasible to apply casing drilling for high angle or near horizontal holes.

SUMMARY OF THE INVENTION

It is an object of the invention to circumvent, at least to a considerable extent, the drawbacks associated with the above method and device.

This object is achieved according to the present invention by carrying out a method for axially moving a tube in a borehole in the lithosphere in accordance with claim 1. The invention further provides a device according to claim 19 which is specifically adapted for carrying out such a method.

By twisting the tube about its axis in a series of alternating, angularly opposite, rotating movements within a limited angular range of rotation, it is possible to use relatively simple, flexible connections extending between fixed couplings to provide a connection between devices rotating jointly or solidarily with the composed tube and the stationary ground. An example of such a flexible connection extending between fixed couplings is e.g. a length of flexible hose or pipe fixed with simple clamps on each end for fluid connections or a length of insulated cable provided with plugs on each end for co-operation with sockets to provide an electrical connection.

The limited rotational angle of this "oscillating" rotational movement will prevent the flexible connections from becoming wound-up too far as would be the case with an increasing rotational angle caused by the rotational movement of the prior art.

Furthermore, during insertion or retraction of a device, e.g. a drill, a packer, a sensor or an inspection apparatus, through the inside of the tube, the tube can be oscillated continuously, thus greatly reducing the risk of the tube getting stuck.

The angular range of rotation can be preselected to comprise approximately one full rotation of 360°, e.g. ranging from - 180° to + 180° or 0° to 360°. The range can also

comprise more than one full rotation, i.e. include an angle of more than 360° in e.g. the interval from 0° to 720° or -360° to $+360^\circ$ or a multiple of this angle or less than one full rotation, e.g. 0° to 180° or -90° to $+90^\circ$. Preferably, less than 5 full rotations in one direction, e.g. left hand rotations, are followed by the same number of full rotations in the opposite direction, e.g. right hand rotations.

The oscillating movement can be such that each alternating angular movement is substantially equal in magnitude, such as to achieve a symmetric pattern. However, it is also possible to perform a series of alternating rotating movements that are not equal in magnitude, e.g. a series of alternating movements that provide a gradual angular drift which may have an oscillating pattern so that the total angle of rotation remains within a limited angular range at all times or be a drift in one sense so that the total angle of rotation remains within a limited angular range for a limited duration only. Such a duration may for instance be of sufficient length to perform operation on or with the tube, such as steering the drilling direction or connecting an end of tube material to the tube.

It shall be clear that within this context the rotational angle within the pre-selected angular range is defined as an absolute angle of rotation of the tube about its axis, relative to the ground.

Furthermore, it shall be clear that when axially moving the tube, a first series of alternating angularly opposite rotating movements performed within a first pre-selected angular range of rotation can be followed by a second series of such movements within a second range.

The frequency of the opposite movements or oscillations is preferably less than several oscillations per minute, typically less than 10 oscillations per minute and/or can be chosen to match the natural frequency of the tube in the ground. In the proposed method the oscillations are preferably performed at 0,1 or 0,05 Hz. The method however

does not exclude the application of a higher frequency of oscillation, e.g. in a typical range from 1 to 50 HZ.

In another advantageous embodiment of the invention a welding or cutting apparatus oscillates substantially jointly or in unison with a composed tube and a rotating tube part to be connected therewith, respectively to be cut therefrom. This enables continuous insertion or retraction of the tube into/from the borehole, as will be elucidated further. It should be noted that welded or other rotationally rigid connections between the successive tube parts are especially advantageous in view of their increased resistance to become undone by the angularly opposite rotational movements compared to the screw connections generally used to couple successive casing or tubing parts. The rotationally rigid connections between the tube elements allow precise control of the relative orientation of the tube end below the surface and the tube part visible at the surface. The use of an axial line provided on the outside of the tube, e.g. by inscription, and precise measurement of the angle between the line on each consecutive tube section will provide an exact knowledge of the orientation of tube end below the surface.

By measuring the torque exerted on the tube at the surface while performing angularly symmetric oscillations, a mid-point position can be determined, characterised by the mid-point of the lower torque values. The azimuth of this mid-point position relative to the azimuth of the inscribed line is indicative for the azimuth of the tube end. The tube end azimuth determined in this way can be corrected for the reactive torque of the drilling tool suspended in the tube end, if necessary.

Another important advantage of the consecutive angularly opposite movement is that, by performing the consecutive movements within a circle segment, a tube having a bent tip can be steered while inserting it axially into the ground. Instead of a bent tip, it is also possible to use other kinds of devices standing-off asymmetrically from the

axis A at the end of the tube tip. In order to change the direction of the borehole to be drilled, i.e. the azimuth and angle of the borehole, the oscillating range is chosen to be symmetrical about a predetermined tube end azimuth and to include less than 360° rotation of the tube end, for instance a range from - 45° to + 45°. These small oscillations achieve that the cutting process at the tube end preferentially removes rock or ground in a circle segment corresponding to the desired hole direction. This process is continued until the desired tube end hole angle in the desired tube end azimuth is achieved. In order to continue the borehole at the same hole angle in the desired tube end azimuth, the oscillations and rotation are adjusted such that the cutting process at the tube end removes equal amounts of rock in all directions. The borehole can thus be steered in the desired direction using surface measurements based on the azimuth of the line and inclination measurements at the tube end. Preferably, a drill is used of which the rate of material removal is independent of the direction or speed of rotation, e.g. a hydraulically powered chisel.

In addition, by providing a mud chamber fixedly connected to a mud supply by means of two flexible hoses, the supply of mud can be continued while tube parts are added to a tube or are separated therefrom.

Particularly advantageous elaborations of the invention are set forth in the dependent claims. Further objects, elaborations, effects and details of the invention appear from the following description, in which reference is made to the drawing.

BRIEF DESCRIPTION OF THE DRAWINGS

Fig. 1 is a schematical cross-section of a casing 1 being inserted in a borehole;

Fig. 2 is a schematical cross-section of a apparatus for composing a casing from casing parts and inserting the

composed casing in a borehole, while simultaneously drilling the borehole;

Fig. 2A is a schematical diagram of yet another embodiment of an apparatus for composing a casing from casing parts and inserting the composed casing in a borehole;

Figs. 3A-E show a mud chamber for providing continuous mud flow while drilling in various stages of operation;

Fig. 4 shows a lower most casing part with a bent tip or for directional drilling; and

Fig. 5 shows a circular segment corresponding to an pre-selected angular range of rotation for directional drilling.

DETAILED DESCRIPTION

Although the exemplary elaborations discussed below generally relate to composing and inserting a casing into a borehole in the ground by means of a casing drilling process, wherein the tube to be inserted carries a drill, similar elaborations can also be applied to insertion of other types of (composed) tubes into a borehole in the ground or retracting such tubes from such a borehole, which tubes need not carry a drill.

Fig. 1 shows a tubular casing 1 which is introduced into a borehole 2 in the ground 3. The casing 1 is composed by connecting successive tubular casing parts 4, e.g. 4A and 4B end-to-end. The first or bottom most casing part 4C carries a collapsable drill 5 having an outer diameter slightly larger than the diameter of the casing parts. The drill 5 is driven by a mud motor 6, which is in turn powered by means of a high-pressure flow of mud induced through the inside of the casing 1. The drill can e.g. comprise a so-called collapsable crushing or gauging drilling bit for removing rock. After passing through the mud motor 6, the mud emerges from the casing 1 at the location of the drill 5 and

washes upwards to the surface 7 between the outer diameter of the casing 1 and the walls of the borehole 2. In the drawing, the flow path is shown with arrows.

It shall be noted that instead of a drill 5 comprising a mud motor/bit combination, a mud hammer assembly with a collapsible chisel type bit can be applied, alternatively high pressure jetting assembly can be applied for rock removal. Instead of powering the drill, hammer or jetting assembly with hydraulic energy, electrical or pneumatic drive mechanisms may also be applied.

It shall also be noted that to ensure that the diameter of the hole 2 is sufficiently large for the casing 1, a cutting structure may be applied to the outside of the tube tip, specifically adapted for operating with an oscillating motion of the tube tip.

The casing 1 is axially advanced along its axis A into the borehole 2 by means of a drilling table 8 mounted above the well head 9, which can include a usual blowout preventor. The well head 9, including the blowout preventor is placed on the surface 7 to seal the area between the casing 1 and the borehole 2.

The drilling table 8 is mounted on leg structures 19 of which the effective length can be changed, e.g. by means of hydraulic cylinders. The drilling table 8 is provided with grippers 10A frictionally engaging the outer circumference of the proximal end of the casing 1 projecting from the borehole 2 beyond the surface 7. These grippers are capable of supporting the full weight of the tube plus the upward friction and transmitting left and right hand torque to the tube to a maximum of the torsional strength limit of the tube. As the drill 5 cuts through the ground 3, the casing 1 is advanced axially along its axis A into the borehole 2 by decreasing the length of the legs 10. To decrease the friction in axial direction between the casing 1 and the borehole 2, the casing is moved about its axis A in a series

of alternating, angularly opposite rotating movements within a pre-selected angular range of rotation.

The consecutive, angularly opposite, rotating movement is for instance performed by firstly rotating the casing 1080° clockwise about its axis relative to the ground, followed by a countering rotation of 1080° counter clockwise, followed by a clockwise rotation of 1080° and so on. Thus, an oscillating movement is performed within a pre-selected range of 0° - 1080°. It shall be clear that it is also possible to start off with a first rotation of e.g. half or double the angle α of the countering movement. Also, it shall be clear that it may be possible to perform consecutive, angularly opposite rotating movements having angular values α that are not equal in size and still remain within the pre-selected range, at least during a preselected time interval

The oscillating movement is generated by control means 30 controlling a motor 11 which drives a rotationally disposed upper portion 12 of the drilling table 8 to rotate in consecutive, angularly opposite rotational movements. The upper portion in turn carries the clamps or grippers 10A for transmitting torque between the upper portion 12 and the casing 1. It shall be clear the entire leg structure 19 may be supported such that it oscillates as one unit. The amount of time needed to perform the two consecutive opposite angular movements is e.g. 10 sec., corresponding with a frequency of oscillation of 0,1 Hz.

It is also possible to vary the time of a full oscillation cycle during the course of inserting the tube in order, for instance to adapt the oscillating frequency to changes in the length and natural frequency of the tube or to requirements brought about by operations to be performed with or on the tube, such as connecting a next end of tube material or steering the tip of the tube into a different direction.

As is clear from fig. 1, the mud supply line 13 comprises a simple, solid-state and safe connection between

the surface 7 and the oscillating casing 1. The mud supply 13 comprises a flexible hose 14 that is fixedly connected to the mud pump 15 by means of clamps on one end and that is fixedly connected by clamps to a packer 16 rotating jointly with the casing 1 on the other end. Due to the fact that the absolute angle α of axial rotation of the casing remains within the pre-selected range, the flexible hose 14 between the mud pump 15 and the packer 16 will not wind up and a rotational seal, called swivel by those skilled in the art, need not be provided.

Furthermore, it is also possible to provide hydraulic, pneumatic and/or electric connections in the same fashion, e.g. flexible hydraulic hoses 17 for operating the packer 16, which are rigidly connected to the packer 16 on the one end and to a hydraulic pressure source 18 on the other end.

As will be clear, during insertion or retraction of the casing 1, the oscillating movement is performed simultaneously with the axial movement. However, when axial displacement of the casing is not necessary, e.g. while the mud motor 6 and/or the drill 5 is retracted, the oscillating movement can be continued, thereby greatly reducing the chance of the casing 1 getting stuck in the borehole 2. In operation, the casing 1 will act as a torsional spring, thereby assisting the motor 11 in driving the casing to oscillate.

Referring to fig. 2 it is shown that in a further embodiment of the invention, in order to decrease down-time and in order to enable continuous insertion of a composed casing 1 into the borehole 2, a second drilling table 20 is provided. This drilling table is of similar construction as the drilling table 8 and is also provided with hydraulically adjustable legs 21, a rotationally disposed upper portion 22 driven by a motor 23 and carrying clamps 24.

The second drilling table 20 also carries guiding means 25 in which a casing part 4B can be inserted, such that

it is axially aligned with the proximal end of the casing 1 projecting from the borehole and can be synchronised in axial oscillation therewith by drives 31, operatively coupled to control means 30. When the tube parts 4A, 4B are disposed
5 end-to-end they can be welded together by means of a welding apparatus 26 disposed on the upper portion 22 of the second drilling table 20, such that it can rotate substantially jointly with the casing 1. Due to the oscillating movement within the pre-selected angular range, the electrical
10 connections 33 between the surface 7 and the welding apparatus 26 can be configured as cables with plugs on each end, while the need for a commutator is obviated. The welding apparatus 26 is disposed within a neutral-gas environment extending both on the radial outside of the casing 1 and the
15 casing part 4B to be connected therewith and on the radial inside thereof. On the radial outside, the neutral gas environment is provided as a chamber 28, while on the radial inside the neutral gas environment is e.g. provided by means of a seal 34, cooperating with the packer 16 to form a
20 chamber 29, such as to create an explosion proof environment for the welding or cutting process. Instead of neutral gas, the welding chamber and the annular space of the tube part to be connected may be flushed with air from a secure source such as to eliminate explosion hazards.

25 The welding apparatus is arranged to rotate about the axis A of the casing, such that a circular weld 34 can be provided between the tube parts.

Preferably, the length of the tube parts 4A, 4B, 4C is chosen in relation to the speed of synchronisation and
30 welding, such that at full speed of insertion, a successive tube part 4B can be connected to the casing 1 before axial insertion of a tube segment is completed. It should be noted that, in order to enable constant axial insertion, the drilling tables 8 and 20 are arranged to cooperate in a relay
35 fashion, such that at any time at least one drilling table rotationally drives the casing and simultaneously inserts the

casing axially into the borehole 2, while the other drilling table stretches its legs. Both tables 8 and 20 may be combined in one unit which oscillates as one assembly. As the tube parts are driven on the radial outside, the motors 11, 23 can be placed relatively close to the surface 7 and a top-drive can be omitted. This way, the casing parts can be hoisted into the guiding means 25 with a conventional crane and a rig structure need not be built.

In an other embodiment of the invention shown in fig. 2A the welding or cutting process is not combined with an upper table 20 to keep the leg structure compact, e.g. with a stroke of typically less than 3 meters. The welding or cutting process in this embodiment is contained in a welding apparatus 26A that is clamped to the tube 1 by means of clamps 26B and comprises alignment means for aligning tube section 4B. The welding apparatus 26A can be moved axially along the tube 1. The table 8A is rotationally disposed on the blowout preventor 9A and allows axial insertion, while the clamps 10B are provided with to retain the tube while the legs 19A are stretched in an upward stroke.

It shall be clear that it is also possible to axially retract the casing 1 from the borehole 2 using the apparatus of figs. 2 and 2A. In this case, instead of a welding apparatus 26, 26A an abrasive cutter or any known cutting process can be installed.

It shall be noted that means may be provided on e.g. the welding apparatus to post-weld heat-treat the connection.

It shall be noted that in addition means may be provided, e.g. on the assembly of hose 14 and packer 16, to remove excess material from the inside of the weld zone. Such means may be configured to fully smoothen or polish the inside of the weld zone. Advantageously, such means are configured to smoothen or polish the entire inside of tube section 4B or to cover it with a coating.

It shall be noted that the assembly of hose 14 and packer 16 may include devices to properly internally align

the tube end protruding from the hole (4A) and the new tube section 4B. Such alignment device may also be integrated with the welding apparatus.

It shall be noted that the welding apparatus may be provided with any type of tools to remove excess welding material and smoothen or polish the outside of the weld zone. This functionality may also be extended such that the entire outside of tube section 4B can be smoothened or polished or covered with a coating.

It shall be clear that it is possible to configure only selected sub-elements of the system to oscillate. The composition of the system can e.g. be such that for example welding or cutting and the replacement of the drilling tools can take place in an oscillating mode, while during normal drilling continuous right or left hand rotation can be performed. In this case a swivel would e.g. be applied with a rotating seal for the mud supply hose. In general, any combination of oscillating and rotating modes can be selected to improve the drilling performance, optimise the design of the equipment etc. In particular, the method may include oscillating rotating movements while welding and/or steering, and continuous rotating movements while drilling.

The constructional details of the drilling table will not be described in detail, many ways of realising the construction will be apparent to the skilled man. For further detail reference is made to international patent applications WO 99/34089, WO 99/34091 and PCT/NL 98/00597.

It should be noted that it is also possible to provide the motors 11, 23 with means for accumulating energy, e.g. a fly wheel or springs, in order to assist the motors 11, 23 when the angular rotational movement is reversed.

It shall be clear that the drilling tables can be used advantageously by themselves. In particular, the rotationally disposed table with the grippers 10 and the motor 11 provided with control means 30 to induce alternating, angularly opposite rotating movements can by

themselves be used to drive a tube or a casing to oscillate, thus reducing the chance of the tube getting stuck in a borehole.

Referring to figs. 3A-E it is elucidated how, due to
5 the oscillating movement, the mud supply can be continued while successive casing parts are connected. Fig. 3A shows that the packer 16 is connected to the flexible hose 14 of the mud supply 13 by means of quick connect coupling 41. When a subsequent casing part 4B is to be connected to the
10 uppermost casing part 4A, a mud chamber 42 is placed on the upper portion of the casing part 4A as shown in fig. 3B. This mud chamber 42 may or may not be part of the structure housing the welding or cutting process. The mud chamber 42 is provided with a side entry 43 where a secondary flexible hose
15 14A is fixedly connected to the mud chamber 42, e.g. by means of a clamp connection. As the mud chamber 42 oscillates jointly with the casing, the connection between the mud chamber 42 and the mud pump 15 can be a simple flexible connection. The mud chamber 42 furthermore comprises seals 44
20 for sealingly connecting it to the casing 1. The mud chamber 42 further comprises an adjustable seal 45, e.g. an hydraulically actuatable diaphragm through which the flexible hose 14A can pass sealingly.

As a first step, the mud chamber 42 is axially moved
25 upwards (fig. 3B) and the mud supply 13 is adjusted to feed mud through the secondary flexible hose 14A, while the supply through the flexible hose 14 is cut (fig. 3C). This can be performed by a set of suitable valves. The mud flow is indicated with arrows P and P1. Simultaneously, the packer 16
30 is released, e.g. by hydraulic operation, and is retracted via the flexible hose 14 until it is located in the mud chamber 43 near the adjustable seal 45.

Subsequently, the flexible hose 14 is released from the quick connect coupling 41 and is axially fed through the
35 casing part 4B that is to be connected to the casing part 4A. Next, the quick connect coupling 41 is reconnected and the

next casing part 4B is placed (fig. 3D). The packer 16 is then lowered into the casing part 4A, as is shown in fig. 3E. When the packer 16 is in place, it is actuated to sealingly engage the inner portion of the casing part 4A, while
5 simultaneously the mud flow is transferred from the secondary flexible hose 14A back to the flexible hose 14. The mud chamber 42 can now be moved axially upward onto the casing section 4B, leaving the abutting edges of the casing parts 4A and 4B free to be welded. After the weld has been realised,
10 the packer 16 can be moved axially upwards, thereby completing the operating cycle 4B.

Alternative methods of inserting casing section 4B includes the pre-installation of hose 14 and packer 16 in the casing 14 to be connected. The mud chamber 42 would then be
15 constructed in such a way that hose 14 and packer 16 can be completely removed from the tube end 4A, and that section 4B including the pre-installed hose 14 and packer 16 assembly can be installed.

The constructional details of the mud chamber 42, the
20 seals 44, 45, the packer 16, the quick connect coupling 41 and the valves needed to direct the mud flow through the flexible hoses are known to the skilled man. In particular a number of advantageous constructive details of the mud chamber are discussed in PCT/NL/98/00597. It should be noted
25 that the method of providing a continuous mud circulation with the disclosed mud chamber can in itself have many advantageous uses. In particular, the fixed, non-rotating connections between the flexible hoses 14, 14A enable simple and reliable operation.

30 In a further embodiment of the invention during displacement of the tube, a technique is applied which is known as reverse circulation in the field. This technique is particularly suitable for the installation of large diameter casing, typically larger than 13 3/8" OD casing and for
35 conditions with weak ground formations in an openhole section. With reverse circulation mud is added to the annular

space between the casing that is installed and a previous, usually cemented casing. However the mud may also be added between the casing that is being installed and an inner tube. The return stream of the mud and the formation fragments liberated by the drilling process will then flow via the casing being installed itself or an inner tube which is connected to the drilling process module. The power to drive the drilling process module can be electrically, hydraulically or pneumatically configured. The differential pressure between the mudflow into the annular space and the return flow to surface can be provided by the injection of air or non combustible gas in the return stream, utilising a technique called airlift by those skilled in the art, or by any other means of maintaining a sufficient pressure differential.

Referring to figs. 4 and 5 it is shown how the casing 1 can be used for directional drilling. To this end, the bottom most casing part 4C is provided with a tip portion 51 extending at an angle β relative to the portion 52. For sake of clarity, the angle β has been drawn on an enlarged scale. However, in practice, the angle β can be chosen at a small value, e.g. 5° or less, preferably $1-3^\circ$. Alternatively the bottom most casing part may be provided with, for example, devices eccentrically stand-off from the axis A to force the casing from a straight line path. When the bottom most casing part 4C or "sub" is rotated about the longitudinal axis A over a full circular segment, i.e. the angular range of rotation is at least 360° , the casing 1 will advance in a straight line when it is advanced axially into the ground 3. However, when the bottom most casing part 4C is oscillated with alternating, angularly opposite rotating movements within a circular segment, i.e. less than 360° e.g. a range of angular rotation including 90° extending from 45° to 135° , ground is removed in only a part of the circumference at the bottom of the lower-most segment and the casing 1 will follow a curved path when it is advanced into the ground 3.

Especially when a casing 1 is used with a high torsional resistance, e.g. a casing with a large diameter or a casing having a composite structure, e.g. fiber reinforced plastic, the torsional lag between the upper portion of the casing projecting from the surface 7 of the ground 3 and the bottom most portion of the casing carrying the drill 5 will be relatively small, such that a high accuracy can be achieved in directional drilling.

It shall be clear that the bottom most casing part 4C having a tip portion extending at an angle β can also be used for directional drilling of a tube that comprises only one segment or a tube of which the tube parts are connected prior to drilling. It can even be envisaged to perform oscillations within a circular segment with such a casing part during conventional, rotating drilling to change direction.

It shall be clear to the skilled man that the invention is not limited to the preferred embodiments discussed herein and that many aspects of the invention can either be used independently of each other or combined. In particular, the method can be used offshore for seabed drilling. Also, the method can be used during underbalanced conditions. Furthermore, the method can be used for inserting a tube in a predrilled borehole and/or a normal drilling rig may be used. Such embodiments are within the scope of the invention as defined in the appended claims.

Claims

1. A method for axially moving a tube in borehole in the ground, wherein the tube is moved simultaneously along and about its axis, characterised in that moving the tube about its axis comprises a series of alternating, angularly opposite, rotating movements, within a limited angular range of rotation.
5
2. A method according to claim 1, characterised in that the limited angular range of rotation is preselected to comprise comprises less than 1800°, preferably less than 1080°, in particular less than 720°.
10
3. A method according to claim 1 or 2, characterised in that the time needed to complete two consecutive, alternating angularly opposite rotating movements is at least 10 s, preferably at least 20 s.
- 15 4. A method according to claim 1 or 2, characterised in that the time for completing two consecutive, alternating angularly opposite rotating movements is such that an oscillation is generated that corresponds to the base or higher order natural frequency of the tube.
- 20 5. A method according to any of claims 1-4, wherein a series of alternating, angularly opposite, rotating movements within the pre-selected angular range of rotation is preceded and/or succeeded by a non-oscillating, continuous rotating movement about its axis.
- 25 6. A method according to any of claims 1-5, characterised in that said tube is composed by connecting successive tube parts rotationally rigid end-to-end.
7. A method according to claim 6, characterised in that tube parts are connected end-to-end by welding.

8. A method according to claim 6 or 7, characterised in that said tube parts are connected while axially inserting the tube into the borehole.
9. A method according to any of claims 1-8, characterised in that the tube is axially moved into the borehole in the ground to form a casing for a borehole..
10. A method according to claim 9, wherein the tube is inserted while a borehole is being drilled by a drill.
11. A method according to any of the previous claims, characterised in that the pre-selected angular range of rotation includes less than 360°, preferably less than 180° to remove ground in a circular segment at the tube end, such that, when the tube is axially advanced into the borehole, a tip of the tube is advanced along a curved path.
12. A method according to any of the preceding claims, characterised in that the torque exerted on the tube at the surface is measured while performing angularly symmetrical opposite, rotating movements within the pre-selected angular range to determine a mid-point of lower torque values.
13. A method according to any one of the preceding claims, characterised in that relative angular orientation of tube sections axially spaced apart is monitored.
14. A method according to claim 13, characterized in that said monitoring includes observing an axial line provided on the outside of the tube.
15. A method according to claim 13, characterized in that said monitoring includes detecting angular orientations of axially spaced magnetic markings on the outside of the tube.
16. A method according to claim 15, characterized in that said series of alternating, angularly opposite, rotating movements have an azimuth at the tube tip, said azimuth at the tube tip being controlled in response to the orientation of the tube in the area of the ground surface.
17. A method according to claim 16, characterized in that a

an alternating torque having an azimuth is exerted to said tube, said azimuth at the tube tip being further controlled in response to the orientation of the tube in the area of the ground surface when said azimuth of said torque occurs.

- 5 18. A method according to any one of the preceding claims characterised in that pumping of mud is continued while a connection with a next tube section is being made via a hose and packer combination which sealingly connects to the tube section in the hole.
- 10 19. A device for axially moving a tube in a borehole in the ground, comprising means for moving the tube along and about its axis, characterised in that the means for moving the tube about its axis comprises a rotational drive that is operatively coupled to control means for controlling the
- 15 drive to perform alternating, angularly opposite, rotating movements within a limited angular range of rotation.
20. A device according to claim 19, characterised in that the limited angular range of rotation is preselected to comprise less than 1800°, preferably less than 1080°, in
- 20 particular less than 720°.
21. A device according to claims 19 or 20, characterised in that the rotational drive and the control means are further configured to selectively control the drive to perform a continuous, non-alternating, rotating movement.
- 25 22. A device according to any of claims 19-21, characterised in that it comprises a welding apparatus for welding tube segments end-to-end to form a composed tube, which welding apparatus is arranged to rotate substantially jointly with the tube to be moved in the borehole.
- 30 23. A device according to claim 22, characterised in that it is provided with means for surface treatment of the inner and/or outer surface of the tube to be inserted.

24. A device according to claim 22 or 23, characterised in that it is provided with means for aligning and positioning tube ends to be connected.

25. A packer for sealing a tube and arranged to rotate
s substantially jointly therewith, comprising connecting means for connecting to a fluid or energy supply, characterised in that said connecting means are arranged to fixedly couple the packer to a flexible fluid or energy supply extending from the fluid source.

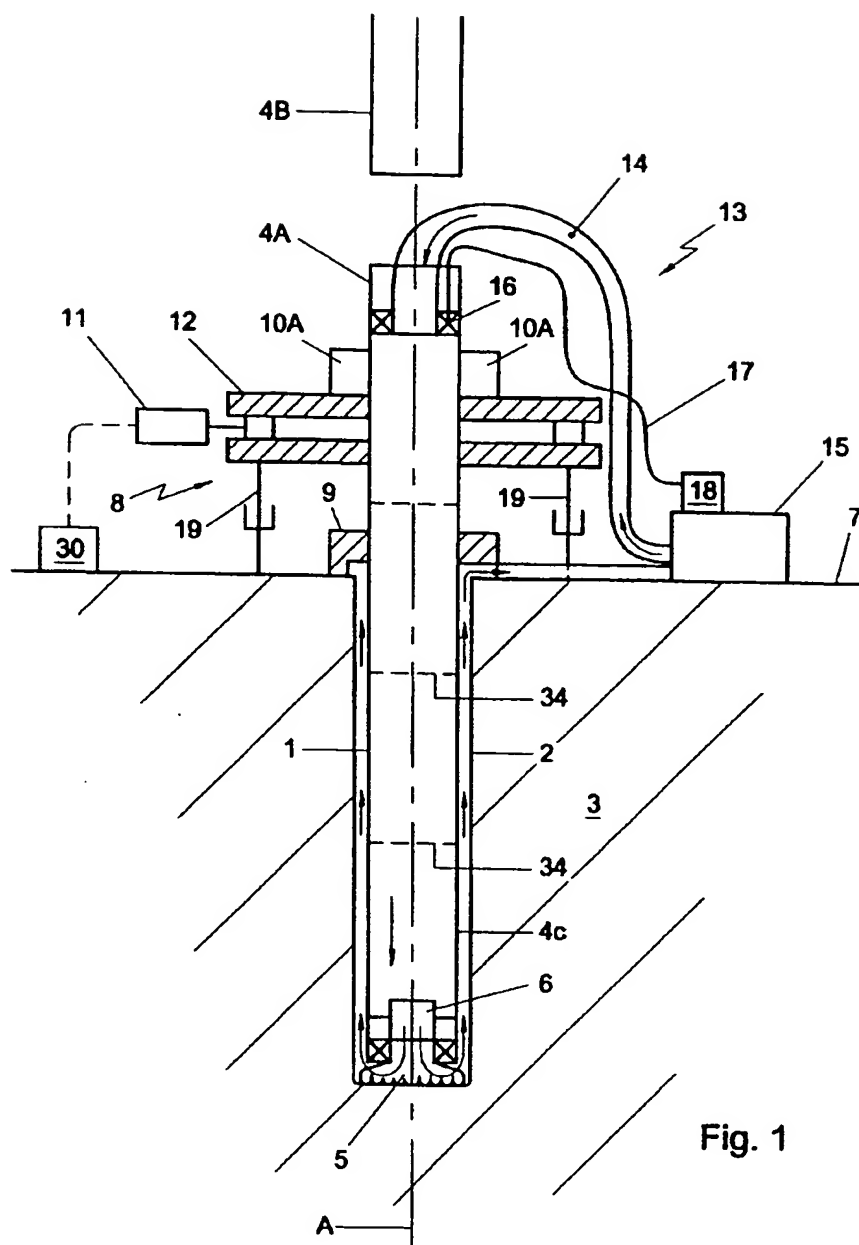


Fig. 1

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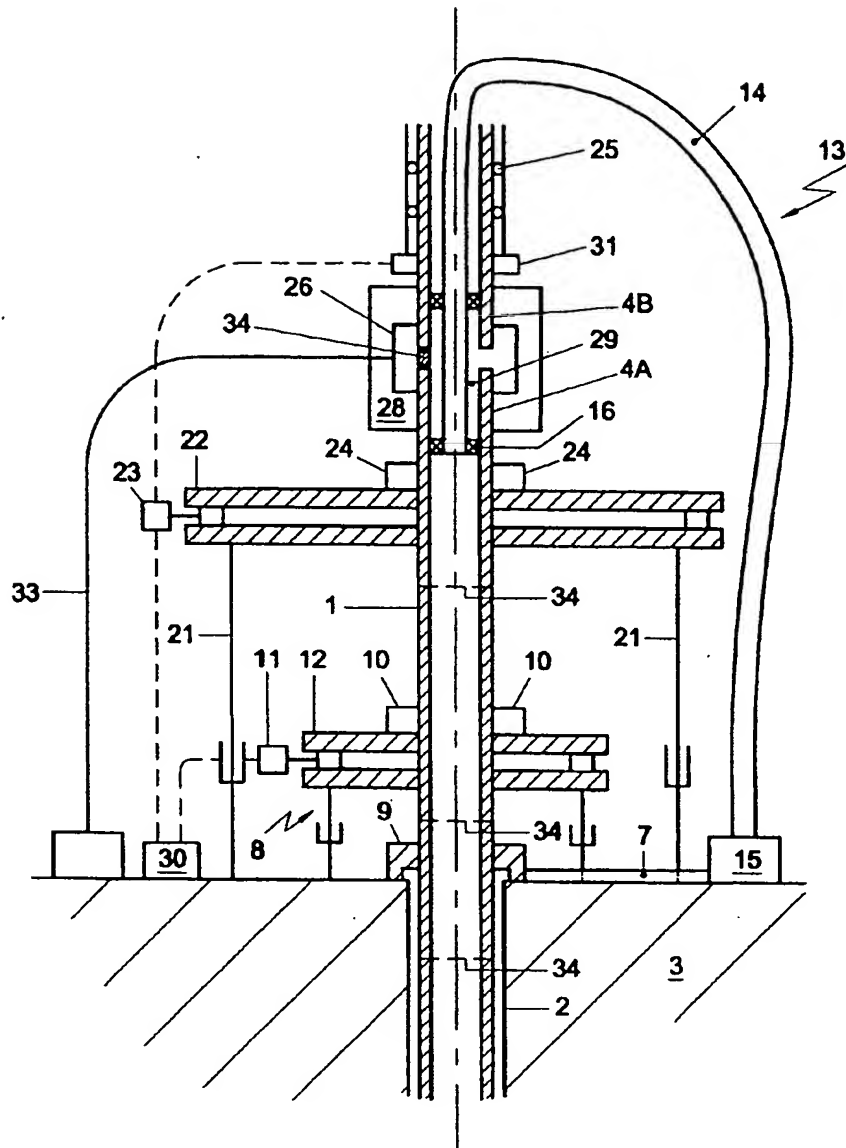
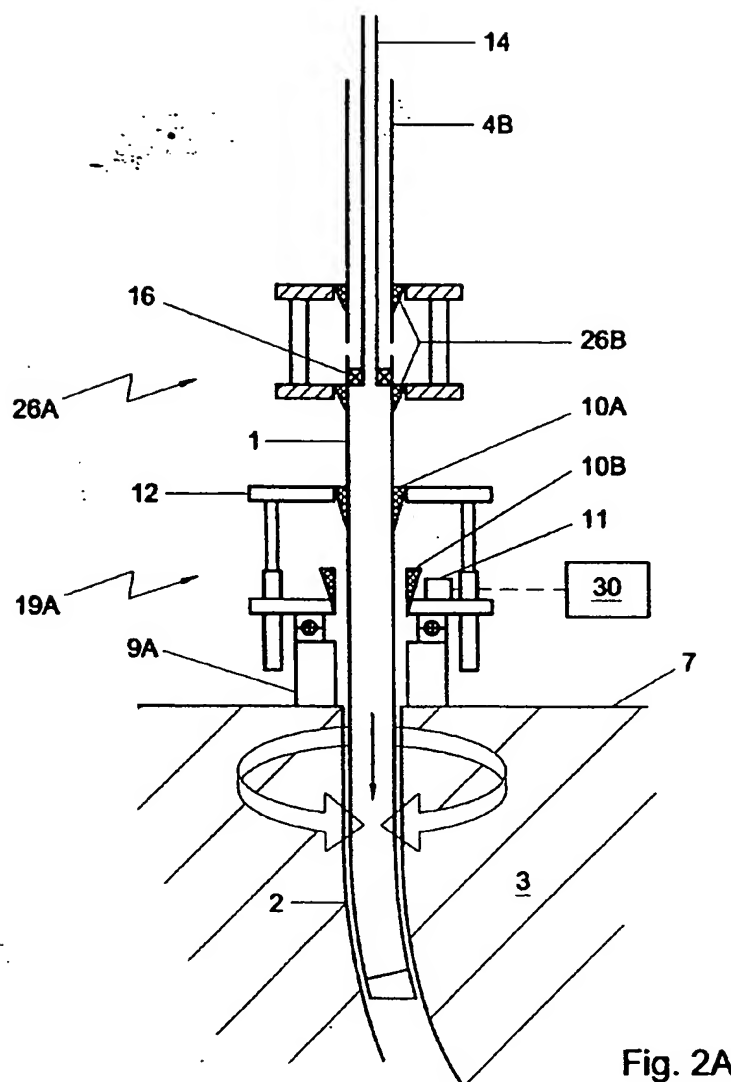


Fig. 2

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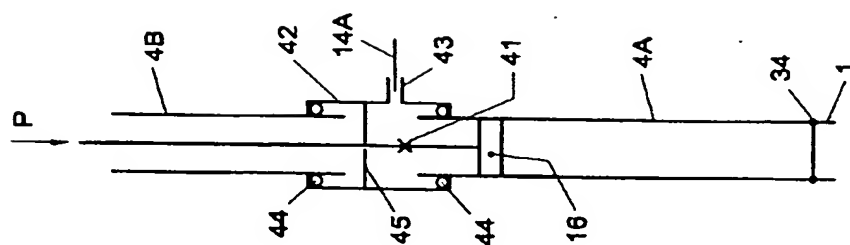


Fig. 3E

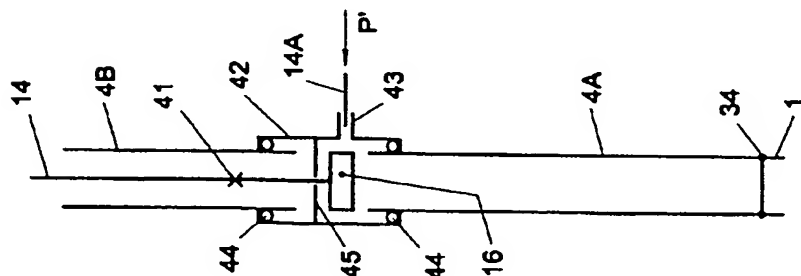


Fig. 3D

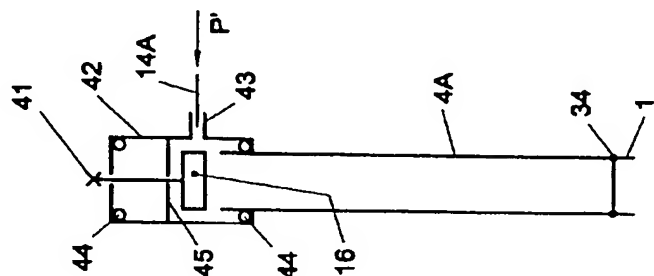


Fig. 3C

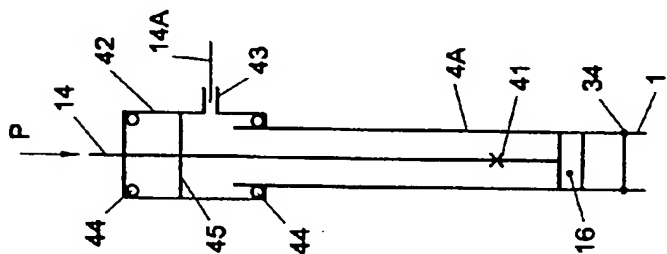


Fig. 3B

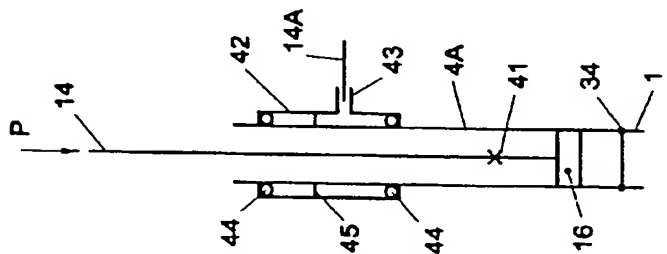


Fig. 3A

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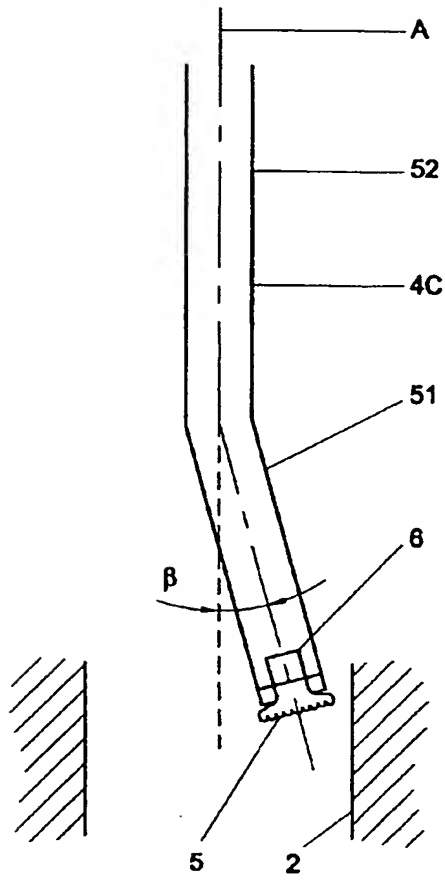


Fig. 4

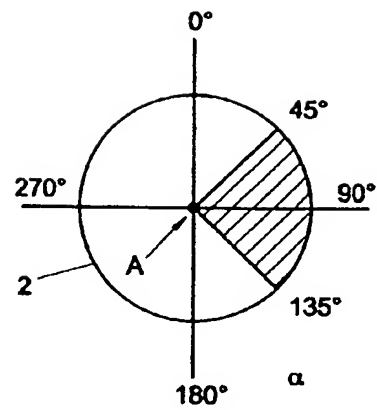


Fig. 5

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INTERNATIONAL SEARCH REPORT

Intern. Application No.

PCT/NL 99/00586

A. CLASSIFICATION OF SUBJECT MATTER		
IPC 7	E2183/025	E2187/24 E21821/01 E2187/06 E2184/20 E21819/16
According to International Patent Classification (IPC) or to both national classification and IPC		
B. FIELDS SEARCHED		
Minimum documentation searched (classification system followed by classification symbols)		
IPC 7 E218		
Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched		
Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)		
C. DOCUMENTS CONSIDERED TO BE RELEVANT		
Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	GB 591 922 A (ALLARD) claim 1 ---	1,2,19, 20
X	GB 521 018 A (HOLMAN BROTHERS LIMITED) claim 1 page 3, line 50 - line 53 ---	1,2,19, 20
X	FR 2 393 114 A (BAUAKADEMIE DER DEUTSCHEN DEMOKRATISCHEN REPUBLIK) 29 December 1978 (1978-12-29) page 1, line 1 - line 5 page 5, line 1 - line 9 ---	1,2,6,8, 9,19,20
Y	---	10
-/--		
<input checked="" type="checkbox"/> Further documents are listed in the continuation of box C. <input checked="" type="checkbox"/> Patent family members are listed in annex.		
* Special categories of cited documents : "A" document defining the general state of the art which is not considered to be of particular relevance "E" earlier document but published on or after the international filing date "L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another claim or other special reason (as specified) "O" document referring to an oral disclosure, use, exhibition or other means "P" document published prior to the international filing date but later than the priority date claimed "T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention "X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone "Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art "Z" document member of the same patent family		
Date of the actual completion of the international search		Date of mailing of the international search report
8 June 2000		03.10.2000
Name and mailing address of the ISA European Patent Office, P.O. Box 5818 Patentweg 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Telex 31 651 epe nl Fax (+31-70) 340-3018		Authorized officer SOGNO M.G.

Form PCT/ISA210 (second sheet) (July 1992)

INTERNATIONAL SEARCH REPORT

Intern. Int. Application No.

PCT/NL 99/00586

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of documents, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	GB 596 715 A (ALLARD) page 1, line 93 - line 102 page 2, line 81 - line 86 page 2, line 63 - line 76 page 1, line 83 - line 89 ---	1,2,5-8, 19-21
Y	---	10
X	DE 18 14 728 A (SALZGITTER MASCHINEN AG) 9 July 1970 (1970-07-09) page X ---	1,2,9, 19,20
X	DE 11 71 848 B (BADE & CO. G.M.B.H.) the whole document ---	1,2,9, 10,19,20
A	US 3 815 691 A (RICHTER) 11 June 1974 (1974-06-11) abstract -----	4

2

Form PCT/ISA/210 (continuation of second sheet) (July 1992)

page 2 of 2

WEST

INTERNATIONAL SEARCH REPORT

International application No.
PCT/NL 99/08586

Box I Observations where certain claims were found unsearchable (Continuation of Item 1 of first sheet)

This International Search Report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:
2. ☐ Claims Nos.:
because they relate to parts of the International Application that do not comply with the prescribed requirements to such an extent that no meaningful International Search can be carried out, specifically:
3. ☐ Claims Nos.:
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box II Observations where unity of invention is lacking (Continuation of Item 2 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

1. ☐ As all required additional search fees were timely paid by the applicant, this International Search Report covers all searchable claims.
2. ☐ As all searchable claims could be searched without effort justifying an additional fee, this Authority did not invite payment of any additional fee.
3. ☐ As only some of the required additional search fees were timely paid by the applicant, this International Search Report covers only those claims for which fees were paid, specifically claims Nos.:
4. ☒ No required additional search fees were timely paid by the applicant. Consequently, this International Search Report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

1 - 10, 19 - 21

Remark on Protest

- ☐ The additional search fees were accompanied by the applicant's protest.
☐ No protest accompanied the payment of additional search fees.

Form PCT/ISA/210 (continuation of first sheet (1)) (July 1998)

WEST

INTERNATIONAL SEARCH REPORT

International Application No. PCT/NL 99/00586

FURTHER INFORMATION CONTINUED FROM PCT/ISA/ 210

1. Claims: 1-10,19-21

method for moving a tube in a borehole, comprising a series of alternating rotating movements matching the natural frequency of the tube.

2. Claims: 11-17

method for moving a tube in a borehole, wherein a tip of the tube is advanced along a curved path.

3. Claims: 18,25

method for moving a tube in a borehole and packer with connecting means to a fluid or energy supply.

4. Claims: 22-24

device for moving a tube in a borehole comprising a rotating welding apparatus, further means for surface treatment of the tube.

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No

PCT/NL 99/00586

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
GB 591922	A	NONE	
GB 521018	A	NONE	
FR 2393114	A	29-12-1978	DD 142490 A 02-07-1980 CS 251601 B 16-07-1987 DE 2817875 A 14-12-1978 HU 179406 B 28-10-1982
GB 596715	A	NONE	
DE 1814728	A	09-07-1970	NONE
DE 1171848	B	NONE	
US 3815691	A	11-06-1974	NONE

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(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
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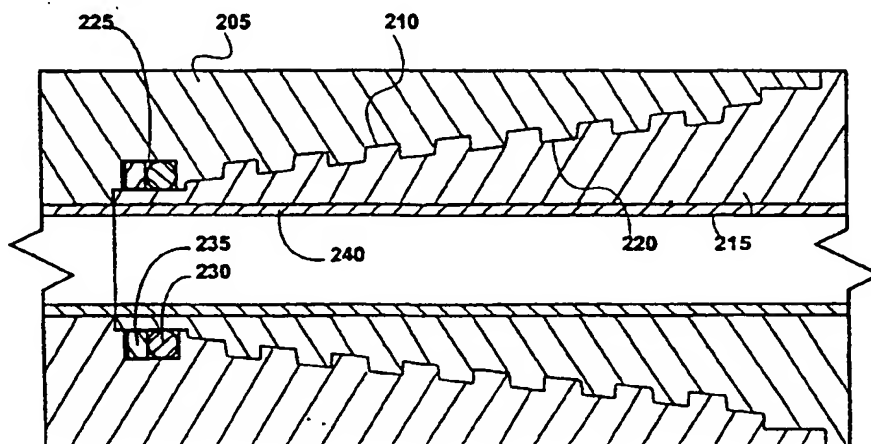
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(US).
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LV, MA, MD, MG, MK, MN, MW, MX, NO, NZ, PL, PT,
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patent (AT, BE, CH, CY, DE, DK, ES, FI, FR, GB, GR, IE,
IT, LU, MC, NL, PT, SE), OAPI patent (BF, BJ, CF, CG,
CI, CM, GA, GN, GW, ML, MR, NE, SN, TD, TG).
- Published:
— With international search report.
— With amended claims.
- For two-letter codes and other abbreviations, refer to the "Guid-
ance Notes on Codes and Abbreviations" appearing at the begin-
ning of each regular issue of the PCT Gazette.

(54) Title: LUBRICANT COATING FOR EXPANDABLE TUBULAR MEMBERS



(57) Abstract: A lubricant coating (240) for expandable tubulars (215). The interior surfaces of the expandable tubulars are coated with the lubricant coating (240). The expandable tubulars (215) are then placed within a preexisting structure (205). The expandable tubulars are then radially expanded into contact with the preexisting structure.

WO 01/26860 A1

LUBRICANT COATING FOR EXPANDABLE TUBULAR MEMBERS

Cross Reference To Related Applications

This application claims the benefit of the filing date of: (1) U.S. Provisional Patent Application serial no. 60/159,039, attorney docket no. 25791.36, filed on October 12, 1999; and (2) U.S. Provisional Patent Application serial no. 60/165,228, attorney docket no. 25791.39, filed on November 12, 1999, the disclosures of which are incorporated herein by reference.

This application is related to the following co-pending applications:

	Provisional Patent Application Number	Attorney Docket No.	Filing Date
10	60/108,558	25791.9	11-16-1998
	60/111,293	25791.3	12-7-1998
	60/119,611	25791.8	2-11-1999
	60/121,702	25791.7	2-25-1999
	60/121,841	25791.12	2-26-1999
15	60/121,907	25791.16	2-26-1999
	60/124,042	25791.11	3-11-1999
	60/131,106	25791.23	4-26-1999
	60/137,998	25791.17	6-7-1999
	60/143,039	25791.26	7-9-1999
20	60/146,203	25791.25	7-29-1999
	60/154,047	25791.29	9-16-1999
	60/159,082	25791.34	10-12-1999
	60/159,039	25791.36	10-12-1999
	60/159,033	25791.37	10-12-1999
25	60/162,671	25791.27	11-01-1999

Applicants incorporate by reference the disclosures of these applications.

Background of the Invention

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are
5 installed in the borehole to prevent collapse of the borehole wall and to prevent
undesired outflow of drilling fluid into the formation or inflow of fluid from the
formation into the borehole. The borehole is drilled in intervals whereby a casing
which is to be installed in a lower borehole interval is lowered through a previously
installed casing of an upper borehole interval. As a consequence of this procedure
10 the casing of the lower interval is of smaller diameter than the casing of the upper
interval. Thus, the casings are in a nested arrangement with casing diameters
decreasing in downward direction. Cement annuli are provided between the outer
surfaces of the casings and the borehole wall to seal the casings from the borehole
wall. As a consequence of this nested arrangement a relatively large borehole
15 diameter is required at the upper part of the wellbore. Such a large borehole
diameter involves increased costs due to heavy casing handling equipment, large
drill bits and increased volumes of drilling fluid and drill cuttings. Moreover,
increased drilling rig time is involved due to required cement pumping, cement
hardening, required equipment changes due to large variations in hole diameters
20 drilled in the course of the well, and the large volume of cuttings drilled and
removed.

The present invention is directed to overcoming one or more of the
limitations of the existing procedures for forming wellbores.

Summary of the Invention

25 According to one aspect of the present invention, an expandable tubular
assembly is provided that includes one or more tubular members and a layer of a
lubricant coupled to the interior surfaces of the tubular members.

According to another aspect of the present invention, a method of coupling
an expandable tubular assembly including one or more tubular members to a
30 preexisting structure is provided that includes coating the interior surfaces of the
tubular members with a lubricant, positioning the tubular members within a

preexisting structure and radially expanding the tubular members into contact with the preexisting structure.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure and one or more tubular members
5 coupled to the preexisting structure. The tubular members are coupled to the preexisting structure by the process of: coating the interior surfaces of the tubular members with a lubricant, positioning the tubular members within a preexisting structure, and radially expanding the tubular members into contact with the preexisting structure.

10 According to another aspect of the present invention, an expandable tubular assembly is provided that includes one or more tubular members, and a layer of a first part of a lubricant coupled to the interior surfaces of the tubular members.

According to another aspect of the present invention, a method of coupling
an expandable tubular assembly including one or more tubular members to a
15 preexisting structure is provided that includes positioning the expandable tubular assembly into the preexisting structure, injecting a quantity of a lubricant material into contact with the expandable tubular assembly, and radially expanding the expandable tubular assembly into contact with the preexisting structure.

According to another aspect of the present invention, an apparatus is
20 provided that includes a preexisting structure and one or more tubular members coupled to the preexisting structure. The tubular members are coupled to the preexisting structure by the process of: positioning the tubular members into the preexisting structure, injecting a quantity of a lubricant material into contact with the tubular members, and radially expanding the tubular members into contact
25 with the preexisting structure.

According to another aspect of the present invention, a method of coupling
an expandable tubular assembly including one or more tubular members to a
preexisting structure is provided that includes coating the interior surfaces of the
tubular members with a first part of a lubricant, positioning the tubular members
30 within a preexisting structure, circulating a fluidic material including a second part of the lubricant into contact with the coating of the first part of the lubricant,

and radially expanding the tubular members into contact with the preexisting structure.

According to another aspect of the present invention, an apparatus is provided that includes a preexisting structure and one or more tubular members coupled to the preexisting structure. The tubular members are coupled to the preexisting structure by the process of: coating the interior surfaces of the tubular members with a first part of a lubricant, positioning the tubular members within a preexisting structure, circulating a fluidic materials having a second part of the lubricant into contact with the coating of the first part of the lubricant, and radially expanding the tubular members into contact with the preexisting structure.

Brief Description of the Drawings

Fig. 1 is a flow chart illustrating a preferred embodiment of a method for coupling a plurality of tubular members to a preexisting structure.

Fig. 2 is cross sectional illustration of a plurality of tubular members including in internal coating of a lubricant.

Fig. 3 is a fragmentary cross sectional illustration of the radial expansion of the tubular members of Fig. 2 into contact with a preexisting structure.

Fig. 4 is a flow chart illustrating an alternative preferred embodiment of a method for coupling a plurality of tubular members to a preexisting structure.

Detailed Description

A method and apparatus for coupling tubular members to a preexisting structure is provided. The internal surfaces of the tubular members are coated with a lubricant. The tubular members are then radially expanded into contact with a preexisting structure. In several alternative embodiments, the method and apparatus are used to form and/or repair a wellbore casing, a pipeline, or a structural support.

In Fig. 1, a preferred embodiment of a method 100 for forming and/or repairing a wellbore casing, pipeline, or structural support includes the steps of: (1) providing one or more tubular members in step 105; (2) applying a lubricant coating to the interior walls of the tubular members in step 110; (3) coupling the

first and second tubular members in step 115; and (4) radially expanding the tubular members into contact with the preexisting structure in step 120.

As illustrated in Fig. 2, in a preferred embodiment, in step 105, a first tubular member 205 having a first threaded portion 210 and a second tubular member 215 having a second threaded portion 220 are provided. The first and second tubular members, 205 and 215, may be any number of conventional commercially available tubular members. In a preferred embodiment, the first tubular member 205 includes a recess 225 containing a sealing member 230 and a retaining ring 235. In a preferred embodiment, the first and second tubular members, 205 and 210, are further provided substantially as disclosed in one or more of the following co-pending applications:

Provisional Patent Application Number	Attorney Docket No.	Filing Date
60/108,558	25791.9	11-16-1998
60/111,293	25791.3	12-7-1998
60/119,611	25791.8	2-11-1999
60/121,702	25791.7	2-25-1999
60/121,841	25791.12	2-26-1999
60/121,907	25791.16	2-26-1999
60/124,042	25791.11	3-11-1999
60/131,106	25791.23	4-26-1999
60/137,998	25791.17	6-7-1999
60/143,039	25791.26	7-9-1999
60/146,203	25791.25	7-29-1999
60/154,047	25791.29	9-16-1999
60/159,082	25791.34	10-12-1999
60/159,039	25791.36	10-12-1999
60/159,033	25791.37	10-12-1999
60/162,671	25791.27	11-01-1999

Applicants incorporate by reference the disclosures of these applications.

In a preferred embodiment, in step 110, a coating 240 of a lubricant is applied to the interior surfaces of the first and second tubular members, 205 and 215. The coating 240 of lubricant may be applied prior to, or after, the first and second tubular members, 205 and 215, are coupled. The coating 240 of lubricant may be applied using any number of conventional methods such as, for example, dipping, spraying, sputter coating or electrostatic deposition. In a preferred embodiment, the coating 240 of lubricant is chemically, mechanically, and/or adhesively bonded to the interior surfaces of the first and second tubular members, 205 and 215, in order to optimally provide a durable and consistent lubricating effect. In a preferred embodiment, the force that bonds the lubricant to the interior surfaces of the first and second tubular members, 205 and 215, is greater than the shear force applied during the radial expansion process.

In a preferred embodiment, the coating 240 of lubricant is applied to the interior surfaces of the first and second tubular members, 205 and 215, by first applying a phenolic primer to the interior surfaces of the first and second tubular members, 205 and 215, and then bonding the coating 240 of lubricant to the phenolic primer using an antifriction paste having the coating 240 of lubricant carried in an epoxy resin. In a preferred embodiment, the antifriction paste includes, by weight, 40-80% epoxy resin, 15-30% molybdenum disulfide, 10-15% graphite, 5-10% aluminum, 5-10% copper, 8-15% aluminosilicate, and 5-10% polyethylenepolyamine. In a preferred embodiment, the antifriction paste is provided substantially as disclosed in U.S. Patent No. 4,329,238, the disclosure of which is incorporated herein by reference.

The coating 240 of lubricant may be any number of conventional commercially available lubricants such as, for example, metallic soaps or zinc phosphates. In a preferred embodiment, the coating 240 of lubricant is compatible with conventional water, oil and synthetic base mud formulations. In a preferred embodiment, the coating 240 of lubricant reduces metal-to-metal frictional forces, operating pressures, reduces frictional forces by about 50%, and provides a coefficient of dynamic friction of between about 0.08 to 0.1 during the radial expansion process. In a preferred embodiment, the coating 240 of lubricant does

not increase the toxicity of conventional base mud formulations and will not sheer in synthetic mud. In a preferred embodiment, the coating 240 of lubricant is stable for temperatures ranging from about -100 to 500 °F. In a preferred embodiment, the coating 240 of lubricant is stable when exposed to shear stresses. In a preferred embodiment, the coating 240 of lubricant is stable for storage periods of up to about 5 years. In a preferred embodiment, the coating 240 of lubricant provides corrosion protection for expandable tubular members during storage and transport.

In a preferred embodiment, the coating 240 of lubricant includes sodium, calcium, and/or zinc stearates; and/or zinc and/or manganese phosphates; and/or C-Lube-10; and/or C-Phos-58-M; and/or C-Phos-58-R; and/or polytetrafluoroethylene (PTFE); and/or molybdenum disulfide; and/or metallic soaps (stearates, oleates, etc...) in order to optimally provide a coating of lubricant. In a preferred embodiment, the coating 240 of lubricant provides a sliding coefficient of friction less than about 0.20 in order to optimally reduce the force required to radially expand the tubular members, 205 and 215, using an expansion cone.

In a preferred embodiment, in step 115, the first and second tubular members, 205 and 215, are coupled. The first and second tubular members, 205 and 215, may be coupled using a threaded connection, or, alternatively, the first and second tubular members, 205 and 215, may be coupled by welding or brazing. In a preferred embodiment, the first and second tubular members, 205 and 215, are coupled substantially as disclosed in provisional patent application serial number 60/159,033, attorney docket number 25791.37, filed on October 12, 1999, the disclosure of which is incorporated herein by reference.

As illustrated in Fig. 3, in steps 120, the first and second tubular members 205 and 215 are then positioned within a preexisting structure 505, and radially expanded into contact with the interior walls of the preexisting structure 505 using an expansion cone 510. The tubular members 205 and 215 may be radially expanded into intimate contact with the interior walls of the preexisting structure 505, for example, by: (1) pushing or pulling the expansion cone 510 through the interior of the tubular members 205 and 215; and/or (2) pressurizing the region

within the tubular members 205 and 215 behind the expansion cone 510 with a fluid. In a preferred embodiment, one or more sealing members 515 are further provided on the outer surface of the tubular members 205 and 215, in order to optimally seal the interface between the radially expanded tubular members 205 and 215 and the interior walls of the preexisting structure 505.

In a preferred embodiment, the radial expansion of the tubular members 205 and 215 into contact with the interior walls of the preexisting structure 505 is performed substantially as disclosed in one or more of the following co-pending patent applications:

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U.S. Provisional Patent Application Number	Attorney Docket No.	Filing Date
60/108,558	25791.9	11-16-1998
60/111,293	25791.3	12-7-1998
60/119,611	25791.8	2-11-1999
60/121,702	25791.7	2-25-1999
60/121,841	25791.12	2-26-1999
60/121,907	25791.16	2-26-1999
60/124,042	25791.11	3-11-1999
60/131,106	25791.23	4-26-1999
60/137,998	25791.17	6-7-1999
60/143,039	25791.26	7-9-1999
60/146,203	25791.25	7-29-1999
60/154,047	25791.29	9-16-1999
60/159,082	25791.34	10-12-1999
60/159,039	25791.36	10-12-1999
60/159,033	25791.37	10-12-1999
60/162,671	25791.27	11-01-1999

The disclosures of each of the above co-pending patent applications are incorporated by reference.

As illustrated in Fig. 4, an alternate embodiment of a method 400 for forming and/or repairing a wellbore casing, pipeline, or structural support includes the steps of: (1) providing one or more tubular members in step 405; (2) applying a coating including a first part of a lubricant to the interior walls of the tubular members in step 410; (3) coupling the first and second tubular members in step 415; and (4) radially expanding the tubular members into contact with the preexisting structure while also circulating fluidic materials into contact with the interior walls of the tubular members having a second part of the lubricant in step 420.

In a preferred embodiment, in step 410, a coating including a first part of a lubricant is applied to the interior walls of the tubular members, 205 and 215. In a preferred embodiment, the first part of the lubricant forms a first part of a metallic soap. In an preferred embodiment, the first part of the lubricant coating includes zinc phosphate.

In a preferred embodiment, in step 420, a second part of the lubricant is circulated within a fluidic carrier into contact with the coating of the first part of the lubricant applied to the interior walls of the tubular members, 205 and 215. In a preferred embodiment, the first and second parts react to form a lubricating layer between the interior walls of the tubular members, 205 and 215, and the exterior surface of the expansion cone. In this manner, a lubricating layer is provided in exact concentration, exactly when and where it is needed. Furthermore, because the second part of the lubricant is circulated in a carrier fluid, the dynamic interface between the interior surfaces of the tubular members, 205 and 215, and the exterior surface of the expansion cone 510 is also preferably provided with hydrodynamic lubrication. In a preferred embodiment, the first and second parts of the lubricant react to form a metallic soap. In a preferred embodiment, the second part of the lubricant is sodium, calcium and/or zinc stearate.

In several experimental exemplary embodiments of the methods 100 and 400, the following observations were made regarding lubricant coatings for expandable tubular members:

- (1) boundary lubrication with a lubricant coating having high adhesion (high film/shear strength) to the expandable tubular is the single-most important lubricant/lubrication process in the radial expansion process;
- 5 (2) hydrodynamic lubrication plays a secondary role in the lubrication process;
- (3) expandable tubular lubricant coating offers the more reliable and more effective form of boundary lubrication;
- 10 (4) a liquid lubricant viscosity and/or film strength that provides effective, consistent boundary lubrication typically limits the effectiveness of additives for the mud alone to provide the necessary lubrication while maintaining drilling fluid properties (rheology, toxicity);
- 15 (5) consistent reductions of 20 to 25 percent in propagation force during the radial expansion process (compared to uncoated expandable tubular control results) were obtained with the following dry film coatings: (1) polytetrafluoroethylene (PTFE), (2) molybdenum disulfide, and (3) metallic soap (stearates), these results are for laboratory tests on one inch dry pipe, in the absence of any drilling fluid;
- 20 (6) a 20 to 25 percent reduction in propagation force during the radial expansion process was observed;
- (7) synthetic oil muds do not typically provide sufficient, reliable lubrication for uncoated pipe;
- 25 (8) the coefficient of friction for expandable tubular lubricant coatings remains essentially constant across a wide temperature range;
- (9) the expected application range for expandable tubular casing expansion is between 40 °F and 400 °F, this range is well within the essentially constant range for coefficient of friction for good coatings;
- 30 and
- (10) good extreme pressure boundary lubricants have a characteristic of performing better (lower coefficients of friction) as the load increases,

coefficients of friction between 0.02 and 0.08 are reported for some coatings.

In a preferred embodiment, the optimum lubrication for in-situ expandable tubular radial expansion operations using the methods 100 and/or 400 includes a combination of lubrication techniques and lubricants. These can be summarized as follows: (1) extreme pressure lubricants/lubrication techniques; and (2) hydrodynamic lubrication from the fluid in the pipe during expansion.

Extreme pressure lubrication is preferably provided by: (1) liquid extreme pressure lubricants added to the fluid (e.g., drilling fluid, etc) in contact with the internal surface of the expandable tubular during the radial expansion process, and/or (2) solid lubricants added to the fluid added to, or contained within, the fluid in contact with the internal surface of the expandable tubular member during the radial expansion process, and/or (3) solid lubricants applied to the internal surface of the expandable tubular member to be radially expanded, and/or (4) combinations of (1), (2) and (3) above.

Liquid extreme pressure lubricant additives preferably work by chemically adhering to or being strongly attracted to the surface of the expandable tubular to be expanded. These types of liquid extreme pressure lubricant additives preferably form a 'film' on the surface of the expandable tubular member. The adhesive strength of this film is preferably greater than the shearing force along the internal surface of the expandable tubular member during the radial expansion process. This adhesive force is referred to as film strength. The film strength can be increased by increasing the viscosity of the fluid. Common viscosifiers, such as polymeric additives, are preferably added to the fluid in contact with the internal surface of the expandable tubular member during the radial expansion process to increase lubrication. In a preferred embodiment, these liquid extreme pressure lubricant additives include one or more of the following: polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives such as, for example, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol/vinyl acetate copolymers, polyvinyl pyrrolidone and copolymers including polyolefins, latexes such as, for example, styrene butadiene latex, urethane latexes, styrene-maleic anhydride

copolymers, viscosity index improvers for motor oils such as polyacrylate esters, block copolymers including styrene, isoprene butadiene and ethylene, ethylene acrylic acid copolymers.

In a preferred embodiment, extreme pressure lubrication is provided using
5 solid lubricants that are applied to the internal surface of the expandable tubular member. These solid lubricants can be applied using various conventional methods of applying a film to a surface. In a preferred embodiment, these solid lubricants are applied in a manner that ensures that the solid lubricants remain on the surface of the expandable tubular member during installation and radial
10 expansion of the expandable tubular member. The solid lubricants preferably include one or more of the following: graphite, molybdenum disulfide, lead powder, antimony oxide, poly tetrafluoroethylene (PTFE), or silicone polymers. Furthermore, blends of these solid lubricants are preferred.

In a preferred embodiment, the solid lubricants are applied directly to the
15 expandable tubulars as coatings. The coating of the solid lubricant preferably includes a binder to help hold or fix the solid lubricant to the expandable tubular. The binders preferably include curable resins such as, for example, epoxies, acrylic, urea-formaldehyde, melamine formaldehyde, furan based resins, acetone formaldehyde, phenolic, alkyd resins, silicone modified alkyd resins, etc. The
20 binder is preferably selected to withstand the expected temperature range, pH, salinity and fluid types during the installation and radial expansion operations. Polymeric materials are preferably used to bind the solid lubricants to the expandable tubular such as, for example, "self-adhesive" polymers such as those copolymers or terpolymers based upon vinyl acetate, vinyl chloride, maleic
25 anhydride/maleic acid, and ethylene-acrylic acid copolymers, ethylene-methacrylic acid copolymers and ethylene-vinyl acetate copolymers. In an alternative embodiment, the solid lubricants are applied as suspensions of fine particles in a carrier solvent without the presence/use of a chemical binder.

In a preferred embodiment, the solid lubricant coating and the liquid
30 lubricant additive (added to the fluid in contact with the internal surface of the expandable tubular member during the radial expansion process) interact during the radial expansion process to improve the overall lubrication. In an exemplary

embodiment, for phosphate solid lubricant coatings, manganese phosphate is preferred over zinc or iron phosphate because it more effectively attracts and retains liquid lubricant additives such as oils, esters, amides, etc.

In a preferred embodiment, solid lubricant coatings use binders that provide
5 low friction that is enhanced under extreme pressure conditions by the presence of the solid lubricant. Preferred solid lubricant coatings includes one or more of the following: graphite, molybdenum disulfide, silicone polymers and polytetrafluoroethylene (PTFE). In a preferred embodiment, blends of these materials are used since each material has lubrication characteristics that
10 optimally work at different stages in the radial expansion process. In a preferred embodiment, a solid, dry film lubricant coating for the internal surface of the expandable tubular includes: (1) 1 to 90 percent solids by volume; (2) more preferably, 5 to 70 percent solids by volume; and (3) most preferably, 15 to 50 percent solids by volume. In a preferred embodiment, the solid lubricants include:
15 (1) 5 to 80 percent graphite; (2) 5 to 80 percent molybdenum disulfide; (3) 1 to 40 percent PTFE; and (4) 1 to 40 percent silicone polymers.

In several exemplary embodiment, the liquid lubricant additives include one or more of the following: (1) esters including: (a) organic acid esters (preferably fatty acid esters) such as, for example, trimethylol propane, isopropyl,
20 penterithritol, n-butyl, etc.; (b) glycerol tri(acetoxy stearate) and N,N' ethylene bis 12 hydroxystearate and octyl hydroxystearate; (c) phosphate and phosphite such as, for example, butylated triphenyl phosphate and isodiphenyl phosphate; (2) sulfurized natural and synthetic oils; (3) alkanolamides such as, for example, coco diethanolamide; (4) amines and amine salts; (5) olefins and polyolefins; (6) C-8 to
25 C-18 linear alcohols and derivatives containing or consisting of esters, amines, carboxylates, etc.; (7) overbased sulfonates such as, for example, calcium sulfonate, sodium sulfonate, magnesium sulfonate; (8) polyethylene glycols; (9) silicones and siloxanes such as, for example, dimethylpolysiloxanes and fluorosilicone derivatives; (10) dinonyl phenols; and (11) ethylene oxide/propylene oxide block
30 copolymers.

An expandable tubular assembly has been described that includes one or more tubular members and a layer of a lubricant coupled to the interior surfaces

of the tubular members. In a preferred embodiment, the lubricant includes a metallic soap. In a preferred embodiment, the lubricant is selected from the group consisting of sodium, calcium, and/or zinc stearates, zinc phosphates, manganese phosphate, C-Lube-10, C-PHOS-58-M, C-PHOS-58-R, graphite, molybdenum disulfide, lead powder, antimony oxide, poly tetrafluoroethylene (PTFE), and silicone polymers. In a preferred embodiment, the lubricant provides a sliding friction coefficient of less than about 0.20. In a preferred embodiment, the lubricant is chemically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the lubricant is mechanically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the lubricant is adhesively bonded to the interior surface of the tubular members. In a preferred embodiment, the lubricant includes epoxy, molybdenum disulfide, graphite, aluminum, copper, aluminosilicate and polyethylenepolyamine. In a preferred embodiment, the layer of lubricant includes: a binder and a solid lubricant material. In a preferred embodiment, the binder is selected from the group consisting of: epoxy, acrylic, urea-formaldehyde, phenolic, alkyd resins, silicone modified alkyd resins, vinyl acetate, vinyl chloride, and maleic anhydride/maleic acid. In a preferred embodiment, the solid lubricant material is selected from the group consisting of: graphite, molybdenum disulfide, silicone polymers, and polytetrafluoroethylene. In a preferred embodiment, the solid lubricant material includes: graphite, molybdenum disulfide, polytetrafluoroethylene, and silicone polymers. In a preferred embodiment, the solid lubricant material includes: about 5 to 80 percent of graphite, about 5 to 80 percent of molybdenum disulfide, about 1 to 40 percent polytetrafluoroethylene, and about 1 to 40 percent silicone polymers. In a preferred embodiment, the layer of lubricant includes about 1% to 90% of the solid lubricant material by volume. In a preferred embodiment, the layer of lubricant includes about 5% to 70% of the solid lubricant material by volume. In a preferred embodiment, the layer of lubricant includes about 15% to 50% of the solid lubricant material by volume.

30 A method of coupling an expandable tubular assembly including one or more tubular members to a preexisting structure has also been described that includes coating the interior surfaces of the tubular members with a lubricant,

positioning the tubular members within a preexisting structure and radially expanding the tubular members into contact with the preexisting structure. In a preferred embodiment, the lubricant coating includes a metallic soap. In a preferred embodiment, the lubricant coating is selected from the group consisting of sodium, calcium, and/or zinc stearates, zinc phosphates, manganese phosphate, C-Lube-10, C-PHOS-58-M, C-PHOS-58-R, graphite, molybdenum disulfide, lead powder, antimony oxide, poly tetrafluoroethylene (PTFE), and silicone polymers. In a preferred embodiment, the lubricant coating provides a sliding friction coefficient of less than about 0.20. In a preferred embodiment, the lubricant coating is chemically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the lubricant coating is mechanically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the lubricant coating is adhesively bonded to the interior surface of the tubular members. In a preferred embodiment, the lubricant coating includes epoxy, molybdenum disulfide, graphite, aluminum, copper, aluminosilicate and polyethylenepolyamine. In a preferred embodiment, the lubricant coating includes: a binder, and a solid lubricant material. In a preferred embodiment, the binder is selected from the group consisting of: epoxy, acrylic, urea-formaldehyde, phenolic, alkyd resins, silicone modified alkyd resins, vinyl acetate, vinyl chloride, and maleic anhydride/maleic acid. In a preferred embodiment, the solid lubricant material is selected from the group consisting of: graphite, molybdenum disulfide, silicone polymers, and polytetrafluoroethylene. In a preferred embodiment, the solid lubricant material includes: graphite, molybdenum disulfide, polytetrafluoroethylene, and silicone polymers. In a preferred embodiment, the solid lubricant material includes: about 5 to 80 percent of graphite, about 5 to 80 percent of molybdenum disulfide, about 1 to 40 percent polytetrafluoroethylene, and about 1 to 40 percent silicone polymers. In a preferred embodiment, the lubricant coating includes about 1% to 90% of the solid lubricant material by volume. In a preferred embodiment, the lubricant coating includes about 5% to 70% of the solid lubricant material by volume. In a preferred embodiment, the lubricant coating includes about 15% to 50% of the solid lubricant material by volume. In a preferred embodiment, the method further includes: injecting a

quantity of a lubricating material into contact with the expandable tubular assembly. In a preferred embodiment, the lubricant coating includes a first part of a lubricating substance; and the lubricating material includes a second part of the lubricating substance.

- 5 An apparatus has also been described that includes a preexisting structure and one or more tubular members coupled to the preexisting structure. The tubular members are coupled to the preexisting structure by the process of: coating the interior surfaces of the tubular members with a lubricant, positioning the tubular members within a preexisting structure, and radially expanding the
- 10 tubular members into contact with the preexisting structure. In a preferred embodiment, the lubricant coating includes a metallic soap. In a preferred embodiment, the lubricant coating is selected from the group consisting of sodium, calcium, and/or zinc stearates, zinc phosphates, manganese phosphate, C-Lube-10, C-PHOS-58-M, C-PHOS-58-R, graphite, molybdenum disulfide, lead powder,
- 15 antimony oxide, poly tetrafluoroethylene (PTFE), and silicone polymers. In a preferred embodiment, the lubricant coating provides a sliding friction coefficient of less than about 0.20. In a preferred embodiment, the lubricant coating is chemically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the lubricant coating is mechanically bonded to the interior surfaces
- 20 of the tubular members. In a preferred embodiment, the lubricant coating is adhesively bonded to the interior surface of the tubular members. In a preferred embodiment, the lubricant coating includes epoxy, molybdenum disulfide, graphite, aluminum, copper, aluminosilicate and polyethylenepolyamine. In a preferred embodiment, the lubricant coating includes: a binder and a solid
- 25 lubricant material. In a preferred embodiment, the binder is selected from the group consisting of: epoxy, acrylic, urea-formaldehyde, phenolic, alkyd resins, silicone modified alkyd resins, vinyl acetate, vinyl chloride, and maleic anhydride/maleic acid. In a preferred embodiment, the solid lubricant material is selected from the group consisting of: graphite, molybdenum disulfide, silicone
- 30 polymers, and polytetrafluoroethylene. In a preferred embodiment, the solid lubricant material includes: graphite, molybdenum disulfide, polytetrafluoroethylene, and silicone polymers. In a preferred embodiment, the

solid lubricant material includes: about 5 to 80 percent of graphite, about 5 to 80 percent of molybdenum disulfide, about 1 to 40 percent polytetrafluoroethylene, and about 1 to 40 percent silicone polymers. In a preferred embodiment, the lubricant coating includes about 1% to 90% of the solid lubricant material by volume. In a preferred embodiment, the lubricant coating includes about 5% to 70% of the solid lubricant material by volume. In a preferred embodiment, the lubricant coating includes about 15% to 50% of the solid lubricant material by volume. In a preferred embodiment, the method further includes: injecting a quantity of a lubricating material into contact with the expandable tubular assembly. In a preferred embodiment, the lubricant coating includes a first part of a lubricating substance; and the injected lubricating material includes a second part of the lubricating substance.

An expandable tubular assembly has also been described that includes one or more tubular members and a layer of a first part of a lubricant coupled to the interior surfaces of the tubular members. In a preferred embodiment, the lubricant includes a metallic soap. In a preferred embodiment, the lubricant is selected from the group consisting of sodium, calcium, and/or zinc stearates, zinc phosphates, manganese phosphate, C-Lube-10, C-PHOS-58-M, C-PHOS-58-R, graphite, molybdenum disulfide, lead powder, antimony oxide, polytetrafluoroethylene (PTFE), and silicone polymers. In a preferred embodiment, the lubricant provides a sliding friction coefficient of less than about 0.20. In a preferred embodiment, the lubricant is chemically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the lubricant is mechanically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the lubricant is adhesively bonded to the interior surface of the tubular members. In a preferred embodiment, the lubricant includes epoxy, molybdenum disulfide, graphite, aluminum, copper, aluminosilicate and polyethylenepolyamine. In a preferred embodiment, the layer of lubricant includes: a binder and a solid lubricant material. In a preferred embodiment, the binder is selected from the group consisting of: epoxy, acrylic, urea-formaldehyde, phenolic, alkyd resins, silicone modified alkyd resins, vinyl acetate, vinyl chloride, and maleic anhydride/maleic acid. In a

preferred embodiment, the solid lubricant material is selected from the group consisting of: graphite, molybdenum disulfide, silicone polymers, and polytetrafluoroethylene. In a preferred embodiment, the solid lubricant material includes: graphite, molybdenum disulfide, polytetrafluoroethylene, and silicone polymers. In a preferred embodiment, the solid lubricant material includes: about 5 to 80 percent of graphite, about 5 to 80 percent of molybdenum disulfide, about 1 to 40 percent polytetrafluoroethylene, and about 1 to 40 percent silicone polymers. In a preferred embodiment, the layer of lubricant includes about 1% to 90% of the solid lubricant material by volume. In a preferred embodiment, the layer of lubricant includes about 5% to 70% of the solid lubricant material by volume. In a preferred embodiment, the layer of lubricant includes about 15% to 50% of the solid lubricant material by volume.

A method of coupling an expandable tubular assembly including one or more tubular members to a preexisting structure has also been described that includes positioning the expandable tubular assembly into the preexisting structure, injecting a quantity of a lubricant material into contact with the expandable tubular assembly, and radially expanding the expandable tubular assembly into contact with the preexisting structure. In a preferred embodiment, the injected lubricant material includes a liquid lubricant material. In a preferred embodiment, the liquid lubricant material is selected from the group consisting of: polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol/vinyl acetate copolymers, polyvinyl pyrrolidone, copolymers including polyolefins, latexes, styrene butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, isoprene butadiene and ethylene, ethylene acrylic acid copolymers, esters, organic acid esters, trimethylol propane, isopropyl, penterithritol, n-butyl, glycerol triacetoxystearate, N,N' ethylene bis 12 hydroxystearate, octyl hydroxystearate, phosphate, phosphite, butylated triphenyl phosphate, isodiphenyl phosphate, sulfurized natural oils, synthetic oils, alkanolamides, coco diethanolamide, amines, amine salts, olefins, polyolefins, C-8

to C-18 linear alcohols and derivatives including esters, amines, carboxylates, overbased sulfonates, calcium sulfonate, sodium sulfonate, magnesium sulfonate, polyethylene glycols, silicones, siloxanes, dimethylpolysiloxanes, fluorosilicone derivatives, dinonyl phenols, and ethylene oxide/propylene oxide block copolymers.

- 5 In a preferred embodiment, the injected lubricant material includes a solid lubricant material. In a preferred embodiment, the solid lubricant material is selected from the group consisting of: graphite, molybdenum disulfide, lead powder, antimony oxide, poly tetrafluoroethylene, and silicone polymers. In a preferred embodiment, the method further includes: coating the interior surfaces
10 of the tubular members with a lubricant prior to positioning the tubular members within the preexisting structure. In a preferred embodiment, the lubricant coating includes a first part of a lubricating substance; and the injected lubricating material includes a second part of the lubricating substance.

- An apparatus has also been described that includes a preexisting structure
15 and one or more tubular members coupled to the preexisting structure. The tubular members are coupled to the preexisting structure by the process of: positioning the tubular members into the preexisting structure, injecting a quantity of a lubricant material into contact with the tubular members, and radially expanding the tubular members into contact with the preexisting
20 structure. In a preferred embodiment, the injected lubricant material includes a liquid lubricant material. In a preferred embodiment, the liquid lubricant material is selected from the group consisting of: polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl
25 acetate polymers, polyvinyl alcohol/vinyl acetate copolymers, polyvinyl pyrrolidone, copolymers including polyolefins, latexes, styrene butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, isoprene butadiene and ethylene, ethylene acrylic acid copolymers, esters, organic acid esters,
30 trimethylol propane, isopropyl, penterithritol, n-butyl, glycerol triacetoxystearate, N,N' ethylene bis 12 hydroxystearate, octyl hydroxystearate, phosphate, phosphite, butylated triphenyl phosphate, isodiphenyl phosphate, sulfurized natural oils,

synthetic oils, alkanolamides, coco diethanolamide, amines, amine salts, olefins, polyolefins, C-8 to C-18 linear alcohols and derivatives including esters, amines, carboxylates, overbased sulfonates, calcium sulfonate, sodium sulfonate, magnesium sulfonate, polyethylene glycols, silicones, siloxanes, dimethylpolysiloxanes, fluorosilicone derivatives, dinonyl phenols, and ethylene oxide/propylene oxide block copolymers. In a preferred embodiment, the injected lubricant material includes a solid lubricant material. In a preferred embodiment, the solid lubricant material is selected from the group consisting of: graphite, molybdenum disulfide, lead powder, antimony oxide, poly tetrafluoroethylene, and silicone polymers. In a preferred embodiment, the apparatus further includes: coating the interior surfaces of the tubular members with a lubricant prior to positioning the tubular members within the preexisting structure. In a preferred embodiment, the lubricant coating includes a first part of a lubricating substance; and the injected lubricating material includes a second part of the lubricating substance.

A method of coupling an expandable tubular assembly including one or more tubular members to a preexisting structure has also been described that includes: coating the interior surfaces of the tubular members with a first part of a lubricant, positioning the tubular members within a preexisting structure, circulating a fluidic material including a second part of the lubricant into contact with the coating of the first part of the lubricant, and radially expanding the tubular members into contact with the preexisting structure. In a preferred embodiment, the lubricant includes a metallic soap. In a preferred embodiment, the lubricant is selected from the group consisting of sodium, calcium, and/or zinc stearates, zinc phosphates, manganese phosphate, C-Lube-10, C-PHOS-58-M, and C-PHOS-58-R. In a preferred embodiment, the lubricant provides a sliding friction coefficient of less than about 0.20. In a preferred embodiment, the first part of the lubricant is chemically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the first part of the lubricant is mechanically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the first part of the lubricant is adhesively bonded to the interior surface of the tubular

members. In a preferred embodiment, the method further includes: combining the first and second parts of the lubricant to generate the lubricant.

An apparatus has also been described that includes a preexisting structure and one or more tubular members coupled to the preexisting structure. The
5 tubular members are coupled to the preexisting structure by the process of: coating the interior surfaces of the tubular members with a first part of a lubricant, positioning the tubular members within a preexisting structure, circulating a fluidic materials having a second part of the lubricant into contact with the coating of the first part of the lubricant, and radially expanding the tubular members into
10 contact with the preexisting structure. In a preferred embodiment, the lubricant includes a metallic soap. In a preferred embodiment, the lubricant is selected from the group consisting of sodium, calcium, and/or zinc stearates, zinc phosphates, manganese phosphate, C-Lube-10, C-PHOS-58-M, and C-PHOS-58-R. In a preferred embodiment, the lubricant provides a sliding friction coefficient of less
15 than about 0.20. In a preferred embodiment, the first part of the lubricant is chemically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the first part of the lubricant is mechanically bonded to the interior surfaces of the tubular members. In a preferred embodiment, the first part of the lubricant is adhesively bonded to the interior surface of the tubular members. In
20 a preferred embodiment, the apparatus further includes combining the first and second parts of the lubricant to generate the lubricant.

Although this detailed description has shown and described illustrative embodiments of the invention, this description contemplates a wide range of modifications, changes, and substitutions. In some instances, one may employ
25 some features of the present invention without a corresponding use of the other features. Accordingly, it is appropriate that readers should construe the appended claims broadly, and in a manner consistent with the scope of the invention.

Claims

- 1 1. An expandable tubular assembly, comprising:
2 one or more tubular members; and
3 a layer of a lubricant coupled to the interior surfaces of the tubular
4 members.
- 1 2. A method of coupling an expandable tubular assembly including one or
2 more tubular members to a preexisting structure, comprising:
3 coating the interior surfaces of the tubular members with a lubricant;
4 positioning the tubular members within a preexisting structure; and
5 radially expanding the tubular members into contact with the preexisting
6 structure.
- 1 3. An apparatus, comprising:
2 a preexisting structure; and
3 one or more tubular members coupled to the preexisting structure by the
4 process of:
5 coating the interior surfaces of the tubular members with a
6 lubricant;
7 positioning the tubular members within a preexisting structure; and
8 radially expanding the tubular members into contact with the
9 preexisting structure.
- 1 4. An expandable tubular assembly, comprising:
2 one or more tubular members; and
3 a layer of a first part of a lubricant coupled to the interior surfaces of the
4 tubular members.
- 1 5. A method of coupling an expandable tubular assembly including one or
2 more tubular members to a preexisting structure, comprising:
3 positioning the expandable tubular assembly into the preexisting structure;

4 injecting a quantity of a lubricant material into contact with the expandable
5 tubular assembly; and
6 radially expanding the expandable tubular assembly into contact with the
7 preexisting structure.

1 6. An apparatus, comprising:
2 a preexisting structure; and
3 one or more tubular members coupled to the preexisting structure by the
4 process of:
5 positioning the tubular members into the preexisting structure;
6 injecting a quantity of a lubricant material into contact with the
7 tubular members; and
8 radially expanding the tubular members into contact with the
9 preexisting structure.

1 7. A method of coupling an expandable tubular assembly including one or
2 more tubular members to a preexisting structure, comprising:
3 coating the interior surfaces of the tubular members with a first part of a
4 lubricant;
5 positioning the tubular members within a preexisting structure;
6 circulating a fluidic material including a second part of the lubricant into
7 contact with the coating of the first part of the lubricant; and
8 radially expanding the tubular members into contact with the preexisting
9 structure.

1 8. An apparatus, comprising:
2 a preexisting structure; and
3 one or more tubular members coupled to the preexisting structure by the
4 process of:
5 coating the interior surfaces of the tubular members with a first part
6 of a lubricant;
7 positioning the tubular members within a preexisting structure;

8 circulating a fluidic materials having a second part of the lubricant
9 into contact with the coating of the first part of the lubricant;
10 and
11 radially expanding the tubular members into contact with the
12 preexisting structure.

AMENDED CLAIMS

[received by the International Bureau on 08 February 2001 (08.02.01)
new claims 9-176 added;
remaining claims unchanged (32 pages)]

1. An expandable tubular assembly, comprising:
one or more tubular members coupled to one another, and
a layer of a lubricant coupled to the interior surfaces of the tubular members.
5
2. A method of coupling an expandable tubular assembly including one or more
tubular members to a preexisting structure, comprising:
coating the interior surfaces of the tubular members with a lubricant;
positioning the tubular members within a preexisting structure; and
10 radially expanding the tubular members into contact with the preexisting
structure.
3. An apparatus, comprising:
a preexisting structure; and
15 one or more tubular members coupled to the preexisting structure by the
process of:
coating the interior surfaces of the tubular members with a lubricant;
positioning the tubular members within a preexisting structure; and
radially expanding the tubular members into contact with the preexisting
20 structure.
4. An expandable tubular assembly, comprising:
one or more tubular members; and
a layer of a first part of a lubricant coupled to the interior surfaces of the tubular
25 members.
5. A method of coupling an expandable tubular assembly including one or more

tubular members to a preexisting structure, comprising:

positioning the expandable tubular assembly into the preexisting structure;
injecting a quantity of a lubricant material into contact with the expandable
tubular assembly; and

5 radially expanding the expandable tubular assembly into contact with the
preexisting structure.

6. An apparatus, comprising:

a preexisting structure; and

10 one or more tubular members coupled to the preexisting structure by the
process of:

positioning the tubular members into the preexisting structure;
injecting a quantity of a lubricant material into contact with the tubular
members; and

15 radially expanding the tubular members into contact with the preexisting
structure.

7. A method of coupling an expandable tubular assembly including one or more
tubular members to a preexisting structure, comprising:

20 coating the interior surfaces of the tubular members with a first part of a
lubricant;

positioning the tubular members within a preexisting structure;

circulating a fluidic material including a second part of the lubricant into contact
with the coating of the first part of the lubricant; and

25 radially expanding the tubular members into contact with the preexisting
structure.

8. An apparatus, comprising:

a preexisting structure; and

one or more tubular members coupled to the preexisting structure by the process of:

coating the interior surfaces of the tubular members with a first part of a lubricant;

5 positioning the tubular members within a preexisting structure;

circulating a fluidic materials having a second part of the lubricant into contact with the coating of the first part of the lubricant; and

radially expanding the tubular members into contact with the preexisting structure.

10

9. The expandable tubular assembly of claim 1, wherein the tubular members comprise wellbore casings.

15

10. The expandable tubular assembly of claim 1, wherein the tubular members comprise underground pipes.

11. The expandable tubular assembly of claim 1, wherein the tubular members comprise structural supports.

20

12. The expandable tubular assembly of claim 1, wherein the coating of lubricant is chemically bonded to the interior surfaces of the tubular members.

13. The expandable tubular assembly of claim 1, wherein the coating of lubricant is mechanically bonded to the interior surfaces of the tubular members.

25

14. The expandable tubular assembly of claim 1, wherein the coating of lubricant is adhesively bonded to the interior surfaces of the tubular members.

15. The expandable tubular assembly of claim 1, wherein the coating of lubricant

includes:

a primer coating coupled to the interior surfaces of the tubular members; and
a coating of an antifriction paste coupled to the primer.

- 5 16. The expandable tubular assembly of claim 1, wherein the coating of lubricant includes, by weight:
 40-80% epoxy resin, 15-30% molybdenum disulfide, 10-15% graphite, 5-10% aluminum, 5-10% copper, 8-15% aluminosilicate, and 5-10% polyethylenepolyamine.
- 10 17. The expandable tubular assembly of claim 1, wherein the coating of lubricant comprises a metallic soap.
- 15 18. The expandable tubular assembly of claim 1, wherein the coating of lubricant comprises zinc phosphate.
19. The expandable tubular assembly of claim 1, wherein the coating of lubricant provides a coefficient of dynamic friction of between about 0.08 to 0.1.
- 20 20. The expandable tubular assembly of claim 1, wherein the coating of lubricant is selected from the group consisting of:
 sodium stearates, calcium stearates, zinc stearates, zinc phosphate, manganese phosphate, C-Lube-10, C-Phos-58-M, C-Phos-58-R,
 polytetrafluoroethylene, molybdenum disulfide, and metallic soaps.
- 25 21. The expandable tubular assembly of claim 1, wherein the coating of lubricant provides a sliding coefficient of friction less than about 0.20.
22. The expandable tubular assembly of claim 1, wherein the coating of lubricant is

74. The apparatus of claim 3, wherein the coating of lubricant comprises:
a solid lubricant; and
a binder.
- 5 75. The apparatus of claim 72, wherein the binder is selected from the group
consisting of:
epoxy, acrylic, urea-formaldehyde, melamine formaldehyde, furan based resin,
acetone formaldehyde, phenolic, alkyd resins, and silicone modified alkyd
resin.
- 10 76. The apparatus of claim 72, wherein the binder is selected from the group
consisting of:
vinyl acetate, vinyl chloride, maleic anhydride, maleic acid, ethylene-acrylic
acid copolymers, ethylene-methacrylic acid copolymers, and ethylene-
15 vinyl acetate copolymers.
77. The apparatus of claim 3, wherein the coating of lubricant comprises a
suspension of particles in a carrier solvent.
- 20 78. The apparatus of claim 3, the coating of lubricant is selected from the group
consisting of:
manganese phosphate, zinc phosphate, and iron phosphate.
79. The apparatus of claim 3, wherein the coating of lubricant comprises:
25 about 1 to 90 percent solids by volume.
80. The apparatus of claim 77, wherein the coating of lubricant comprises:
about 5 to 70 percent solids by volume.

69. The apparatus of claim 3, wherein the coating of lubricant provides a coefficient of dynamic friction of between about 0.08 to 0.1.

70. The apparatus of claim 3, wherein the coating of lubricant is selected from the group consisting of:

sodium stearates, calcium stearates, zinc stearates, zinc phosphate, manganese phosphate, C-Lube-10, C-Phos-58-M, C-Phos-58-R, polytetrafluoroethylene, molybdenum disulfide, and metallic soaps.

71. The apparatus of claim 3, wherein the coating of lubricant provides a sliding coefficient of friction less than about 0.20.

72. The apparatus of claim 3, wherein the coating of lubricant is selected from the group consisting of:

polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol acetate copolymers, polyvinyl vinyl acetate copolymers, polyvinyl pyrrolidone and copolymers including polyolefins, latexes, styrene butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, block copolymers including isoprene butadiene, block copolymers including ethylene, and ethylene acrylic acid copolymers.

73. The apparatus of claim 3, wherein the coating of lubricant is selected from the group consisting of:

graphite, molybdenum disulfide, lead powder, antimony oxide, polytetrafluoroethylene, and silicone polymers.

60. The apparatus of claim 3, wherein the tubular members comprise underground pipes.
- 5 61. The apparatus of claim 3, wherein the tubular members comprise structural supports.
62. The apparatus of claim 3, wherein the coating of lubricant is chemically bonded to the interior surfaces of the tubular members.
- 10 63. The apparatus of claim 3, wherein the coating of lubricant is mechanically bonded to the interior surfaces of the tubular members.
64. The apparatus of claim 3, wherein the coating of lubricant is adhesively bonded to the interior surfaces of the tubular members.
- 15 65. The apparatus of claim 3, wherein the coating of lubricant includes:
a primer coating coupled to the interior surfaces of the tubular members; and
a coating of an antifriction paste coupled to the primer.
- 20 66. The apparatus of claim 3, wherein the coating of lubricant includes, by weight:
40-80% epoxy resin, 15-30% molybdenum disulfide, 10-15% graphite, 5-10%
aluminum, 5-10% copper, 8-15% aluminosilicate, and 5-10%
polyethylenepolyamine.
- 25 67. The apparatus of claim 3, wherein the coating of lubricant comprises a metallic soap.
68. The apparatus of claim 3, wherein the coating of lubricant comprises zinc phosphate.

57. The method of claim 2, wherein the coating of lubricant comprises:
about 5 to 80 percent graphite;
about 5 to 80 percent molybdenum disulfide;
about 1 to 40 percent PTFE; and
5 about 1 to 40 percent silicone polymers.
58. The method of claim 2, wherein the coating of lubricant comprises one or more
of the following:
ester;
10 sulfurized oil;
alkanolamides;
amine;
amine salt;
olefin;
15 polyolefins;
C-8 to C-18 linear alcohol;
derivative of C-8 to C-18 linear alcohol including ester;
derivative of C-8 to C-18 linear alcohol including amine;
derivative of C-8 to C-18 linear alcohol including carboxylate;
20 sulfonate;
polyethylene glycol;
silicone;
siloxane;
dinonyl phenol;
25 ethylene oxide block copolymer; and
propylene oxide block copolymer.
59. The apparatus of claim 3, wherein the tubular members comprise wellbore
casings.

a binder.

50. The method of claim 47, wherein the binder is selected from the group consisting of:

5 epoxy, acrylic, urea-formaldehyde, melamine formaldehyde, furan based resin, acetone formaldehyde, phenolic, alkyd resins, and silicone modified alkyd resin.

51. The method of claim 47, wherein the binder is selected from the group consisting of:

10 vinyl acetate, vinyl chloride, maleic anhydride, maleic acid, ethylene-acrylic acid copolymers, ethylene-methacrylic acid copolymers, and ethylene-vinyl acetate copolymers.

15 52. The method of claim 2, wherein the coating of lubricant comprises a suspension of particles in a carrier solvent.

53. The method of claim 2, the coating of lubricant is selected from the group consisting of:

20 manganese phosphate, zinc phosphate, and iron phosphate.

54. The method of claim 2, wherein the coating of lubricant comprises: about 1 to 90 percent solids by volume.

25 55. The method of claim 52, wherein the coating of lubricant comprises: about 5 to 70 percent solids by volume.

56. The method of claim 53, wherein the coating of lubricant comprises: about 15 to 50 percent solids by volume.

45. The method of claim 2, wherein the coating of lubricant is selected from the group consisting of:

sodium stearates, calcium stearates, zinc stearates, zinc phosphate, manganese phosphate, C-Lube-10, C-Phos-58-M, C-Phos-58-R,
5 polytetrafluoroethylene, molybdenum disulfide, and metallic soaps.

46. The method of claim 2, wherein the coating of lubricant provides a sliding coefficient of friction less than about 0.20.

10 47. The method of claim 2, wherein the coating of lubricant is selected from the group consisting of:

polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol acetate copolymers, polyvinyl vinyl acetate copolymers, polyvinyl pyrrolidone and copolymers including polyolefins, latexes, styrene butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, block copolymers including isoprene
15 butadiene, block copolymers including ethylene, and ethylene acrylic acid copolymers.
20

48. The method of claim 2, wherein the coating of lubricant is selected from the group consisting of:

25 graphite, molybdenum disulfide, lead powder, antimony oxide, polytetrafluoroethylene, and silicone polymers.

49. The method of claim 2, wherein the coating of lubricant comprises:
a solid lubricant; and

supports.

37. The method of claim 2, wherein the coating of lubricant is chemically bonded to the interior surfaces of the tubular members.

5

38. The method of claim 2, wherein the coating of lubricant is mechanically bonded to the interior surfaces of the tubular members.

10

39. The method of claim 2, wherein the coating of lubricant is adhesively bonded to the interior surfaces of the tubular members.

15

40. The method of claim 2, wherein the coating of lubricant includes:
a primer coating coupled to the interior surfaces of the tubular members; and
a coating of an antifriction paste coupled to the primer.

20

41. The method of claim 2, wherein the coating of lubricant includes, by weight:
40-80% epoxy resin, 15-30% molybdenum disulfide, 10-15% graphite, 5-10%
aluminum, 5-10% copper, 8-15% aluminosilicate, and 5-10%
polyethylenepolyamine.

25

42. The method of claim 2, wherein the coating of lubricant comprises a metallic soap.

43. The method of claim 2, wherein the coating of lubricant comprises zinc phosphate.

44. The method of claim 2, wherein the coating of lubricant provides a coefficient of dynamic friction of between about 0.08 to 0.1.

about 1 to 40 percent silicone polymers.

33. The expandable tubular assembly of claim 1, wherein the coating of lubricant comprises one or more of the following:

- 5 ester;
- sulfurized oil;
- alkanolamides;
- amine;
- amine salt;
- 10 olefin;
- polyolefins;
- C-8 to C-18 linear alcohol;
- derivatives of C-8 to C-18 linear alcohol including ester;
- derivatives of C-8 to C-18 linear alcohol including amine;
- 15 derivatives of C-8 to C-18 linear alcohol including carboxylate;
- sulfonate;
- polyethylene glycol;
- silicone;
- siloxane;
- 20 dinonyl phenol;
- ethylene oxide block copolymer; and
- propylene oxide block copolymer.

25 34. The method of claim 2, wherein the tubular members comprise wellbore casings.

35. The method of claim 2, wherein the tubular members comprise underground pipes.

36. The method of claim 2, wherein the tubular members comprise structural

from the group consisting of:

vinyl acetate, vinyl chloride, maleic anhydride, maleic acid, ethylene-acrylic acid copolymers, ethylene-methacrylic acid copolymers, and ethylene-vinyl acetate copolymers.

5

27. The expandable tubular assembly of claim 1, wherein the coating of lubricant comprises a suspension of particles in a carrier solvent.

10

28. The expandable tubular assembly of claim 1, the coating of lubricant is selected from the group consisting of:

manganese phosphate, zinc phosphate, and iron phosphate.

15

29. The expandable tubular assembly of claim 1, wherein the coating of lubricant comprises:

about 1 to 90 percent solids by volume.

20

30. The expandable tubular assembly of claim 29, wherein the coating of lubricant comprises:

about 5 to 70 percent solids by volume.

31. The expandable tubular assembly of claim 30, wherein the coating of lubricant comprises:

about 15 to 50 percent solids by volume.

25

32. The expandable tubular assembly of claim 1, wherein the coating of lubricant comprises:

about 5 to 80 percent graphite;

about 5 to 80 percent molybdenum disulfide;

about 1 to 40 percent PTFE; and

selected from the group consisting of:

polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose
derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose,
polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol
5 acetate copolymers, polyvinyl vinyl acetate copolymers, polyvinyl
pyrrolidone and copolymers including polyolefins, latexes, styrene
butadiene latex, urethane latexes, styrene-maleic anhydride copolymers,
viscosity index improvers for motor oils, polyacrylate esters, block
copolymers including styrene, block copolymers including isoprene
10 butadiene, block copolymers including ethylene, and ethylene acrylic acid
copolymers.

23. The expandable tubular assembly of claim 1, wherein the coating of lubricant is
selected from the group consisting of:

15 graphite, molybdenum disulfide, lead powder, antimony oxide, poly
tetrafluoroethylene, and silicone polymers.

24. The expandable tubular assembly of claim 1, wherein the coating of lubricant
comprises:

20 a solid lubricant; and
a binder.

25. The expandable tubular assembly of claim 24, wherein the binder is selected
from the group consisting of:

25 epoxy, acrylic, urea-formaldehyde, melamine formaldehyde, furan based resin,
acetone formaldehyde, phenolic, alkyd resins, and silicone modified alkyd
resin.

26. The expandable tubular assembly of claim 24, wherein the binder is selected

120. The method of claim 5, wherein the lubricant is selected from the group consisting of:

manganese phosphate, zinc phosphate, and iron phosphate.

5 121. The method of claim 5, wherein the lubricant comprises:
about 1 to 90 percent solids by volume.

122. The method of claim 119, wherein the lubricant comprises:
about 5 to 70 percent solids by volume.

10

123. The method of claim 120, wherein the lubricant comprises:
about 15 to 50 percent solids by volume.

15

124. The method of claim 5, wherein the lubricant comprises:
about 5 to 80 percent graphite;
about 5 to 80 percent molybdenum disulfide;
about 1 to 40 percent PTFE; and
about 1 to 40 percent silicone polymers.

20

125. The method of claim 5, wherein the lubricant comprises one or more of the following:

ester;

sulfurized oil;

alkanolamides;

25

amine;

amine salt;

olefin;

polyolefins;

C-8 to C-18 linear alcohol;

consisting of:

sodium stearates, calcium stearates, zinc stearates, zinc phosphate, manganese phosphate, C-Lube-10, C-Phos-58-M, C-Phos-58-R, polytetrafluoroethylene, molybdenum disulfide, and metallic soaps.

5

116. The method of claim 5, wherein the lubricant provides a sliding coefficient of friction less than about 0.20.

10

117. The method of claim 5, wherein the lubricant is selected from the group consisting of:

polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol acetate copolymers, polyvinyl vinyl acetate copolymers, polyvinyl pyrrolidone and copolymers including polyolefins, latexes, styrene butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, block copolymers including isoprene butadiene, block copolymers including ethylene, and ethylene acrylic acid copolymers.

15

20

118. The method of claim 5, wherein the lubricant is selected from the group consisting of:

graphite, molybdenum disulfide, lead powder, antimony oxide, poly tetrafluoroethylene, and silicone polymers.

25

119. The method of claim 5, wherein the lubricant comprises a suspension of particles in a carrier solvent.

- polyolefins;
C-8 to C-18 linear alcohol;
derivatives of C-8 to C-18 linear alcohol including ester;
derivatives of C-8 to C-18 linear alcohol including amine;
5 derivatives of C-8 to C-18 linear alcohol including carboxylate;
sulfonate;
polyethylene glycol;
silicone;
siloxane;
10 dinonyl phenol;
ethylene oxide block copolymer; and
propylene oxide block copolymer.
109. The method of claim 5, wherein the tubular members comprise wellbore casings.
- 15 110. The method of claim 5, wherein the tubular members comprise underground pipes.
111. The method of claim 5, wherein the tubular members comprise structural
20 supports.
112. The method of claim 5, wherein the lubricant comprises a metallic soap.
113. The method of claim 5, wherein the lubricant comprises zinc phosphate.
- 25 114. The method of claim 5, wherein the lubricant provides a coefficient of dynamic friction of between about 0.08 to 0.1.
115. The method of claim 5, wherein the lubricant is selected from the group

manganese phosphate, zinc phosphate, and iron phosphate.

104. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant comprises:

5 about 1 to 90 percent solids by volume.

105. The expandable tubular assembly of claim 102, wherein the layer of the first part of the lubricant comprises:

10 about 5 to 70 percent solids by volume.

106. The expandable tubular assembly of claim 103, wherein the layer of the first part of the lubricant comprises:

 about 15 to 50 percent solids by volume.

15 107. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant comprises:

 about 5 to 80 percent graphite;

 about 5 to 80 percent molybdenum disulfide;

 about 1 to 40 percent PTFE; and

20 about 1 to 40 percent silicone polymers.

108. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant comprises one or more of the following:

25 ester;

 sulfurized oil;

 alkanolamides;

 amine;

 amine salt;

 olefin;

copolymers.

98. The expandable tubular assembly of claim 4, wherein the lubricant is selected from the group consisting of:

5 graphite, molybdenum disulfide, lead powder, antimony oxide, poly
 tetrafluoroethylene, and silicone polymers.

99. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant comprises:

10 a solid lubricant; and
 a binder.

100. The expandable tubular assembly of claim 97, wherein the binder is selected from the group consisting of:

15 epoxy, acrylic, urea-formaldehyde, melamine formaldehyde, furan based resin,
 acetone formaldehyde, phenolic, alkyd resins, and silicone modified alkyd
 resin.

101. The expandable tubular assembly of claim 97, wherein the binder is selected from the group consisting of:

20 vinyl acetate, vinyl chloride, maleic anhydride, maleic acid, ethylene-acrylic
 acid copolymers, ethylene-methacrylic acid copolymers, and ethylene-
 vinyl acetate copolymers.

25 102. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant comprises a suspension of particles in a carrier solvent.

103. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant is selected from the group consisting of:

92. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant comprises a metallic soap.
93. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant comprises zinc phosphate.
94. The expandable tubular assembly of claim 4, wherein the lubricant provides a coefficient of dynamic friction of between about 0.08 to 0.1.
95. The expandable tubular assembly of claim 4, wherein the lubricant is selected from the group consisting of:
sodium stearates, calcium stearates, zinc stearates, zinc phosphate, manganese phosphate, C-Lube-10, C-Phos-58-M, C-Phos-58-R, polytetrafluoroethylene, molybdenum disulfide, and metallic soaps.
96. The expandable tubular assembly of claim 4, wherein the lubricant provides a sliding coefficient of friction less than about 0.20.
97. The expandable tubular assembly of claim 4, wherein the lubricant is selected from the group consisting of:
polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol acetate copolymers, polyvinyl vinyl acetate copolymers, polyvinyl pyrrolidone and copolymers including polyolefins, latexes, styrene butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, block copolymers including isoprene butadiene, block copolymers including ethylene, and ethylene acrylic acid

84. The expandable tubular assembly of claim 4, wherein the tubular members comprise wellbore casings.
- 5 85. The expandable tubular assembly of claim 4, wherein the tubular members comprise underground pipes.
86. The expandable tubular assembly of claim 4, wherein the tubular members comprise structural supports.
- 10 87. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant is chemically bonded to the interior surfaces of the tubular members.
88. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant is mechanically bonded to the interior surfaces of the tubular members.
- 15 89. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant is adhesively bonded to the interior surfaces of the tubular members.
90. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant includes:
- 20 a primer coating coupled to the interior surfaces of the tubular members; and
a coating of an antifriction paste coupled to the primer.
91. The expandable tubular assembly of claim 4, wherein the layer of the first part of the lubricant includes, by weight:
- 25 40-80% epoxy resin, 15-30% molybdenum disulfide, 10-15% graphite, 5-10% aluminum, 5-10% copper, 8-15% aluminosilicate, and 5-10% polyethylenepolyamine.

81. The apparatus of claim 78, wherein the coating of lubricant comprises:
about 15 to 50 percent solids by volume.
82. The apparatus of claim 3, wherein the coating of lubricant comprises:
5 about 5 to 80 percent graphite;
about 5 to 80 percent molybdenum disulfide;
about 1 to 40 percent PTFE; and
about 1 to 40 percent silicone polymers.
- 10 83. The apparatus of claim 3, wherein the coating of lubricant comprises one or
more of the following:
ester;
sulfurized oil;
alkanolamides;
15 amine;
amine salt;
olefin;
polyolefins;
C-8 to C-18 linear alcohol;
20 derivative of C-8 to C-18 linear alcohol including ester;
derivative of C-8 to C-18 linear alcohol including amine;
derivative of C-8 to C-18 linear alcohol including carboxylate;
sulfonate;
polyethylene glycol;
25 silicone;
siloxane;
dinonyl phenol;
ethylene oxide block copolymer; and
propylene oxide block copolymer.

derivative of C-8 to C-18 linear alcohol including ester;
derivative of C-8 to C-18 linear alcohol including amine;
derivative of C-8 to C-18 linear alcohol including carboxylate;
sulfonate;
5 polyethylene glycol;
silicone;
siloxane;
dinonyl phenol;
ethylene oxide block copolymer; and
10 propylene oxide block copolymer.

126. The apparatus of claim 6, wherein the tubular members comprise wellbore casings.
- 15 127. The apparatus of claim 6, wherein the tubular members comprise underground pipes.
128. The apparatus of claim 6, wherein the tubular members comprise structural supports.
- 20 129. The apparatus of claim 6, wherein the lubricant comprises a metallic soap.
130. The apparatus of claim 6, wherein the lubricant comprises zinc phosphate.
- 25 131. The apparatus of claim 6, wherein the lubricant provides a coefficient of dynamic friction of between about 0.08 to 0.1.
132. The apparatus of claim 6, wherein the lubricant is selected from the group consisting of:

sodium stearates, calcium stearates, zinc stearates, zinc phosphate, manganese phosphate, C-Lube-10, C-Phos-58-M, C-Phos-58-R, polytetrafluoroethylene, molybdenum disulfide, and metallic soaps.

5 133. The apparatus of claim 6, wherein the lubricant provides a sliding coefficient of friction less than about 0.20.

134. The apparatus of claim 6, wherein the lubricant is selected from the group consisting of:

10 polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol acetate copolymers, polyvinyl vinyl acetate copolymers, polyvinyl pyrrolidone and copolymers including polyolefins, latexes, styrene
15 butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, block copolymers including isoprene butadiene, block copolymers including ethylene, and ethylene acrylic acid copolymers.

20

135. The apparatus of claim 6, wherein the lubricant is selected from the group consisting of:

graphite, molybdenum disulfide, lead powder, antimony oxide, poly
25 tetrafluoroethylene, and silicone polymers.

25

136. The apparatus of claim 6, wherein the lubricant comprises a suspension of particles in a carrier solvent.

137. The apparatus of claim 6, wherein the lubricant is selected from the group

consisting of:

manganese phosphate, zinc phosphate, and iron phosphate.

- 5 138. The apparatus of claim 6, wherein the lubricant comprises:
 about 1 to 90 percent solids by volume.
139. The apparatus of claim 136, wherein the lubricant comprises:
 about 5 to 70 percent solids by volume.
- 10 140. The apparatus of claim 137, wherein the lubricant comprises:
 about 15 to 50 percent solids by volume.
141. The apparatus of claim 6, wherein the lubricant comprises:
 about 5 to 80 percent graphite;
15 about 5 to 80 percent molybdenum disulfide;
 about 1 to 40 percent PTFE; and
 about 1 to 40 percent silicone polymers.
142. The apparatus of claim 6, wherein the lubricant comprises one or more of the
20 following:
 ester;
 sulfurized oil;
 alkanolamides;
 amine;
25 amine salt;
 olefin;
 polyolefins;
 C-8 to C-18 linear alcohol;
 derivative of C-8 to C-18 linear alcohol including ester;

derivative of C-8 to C-18 linear alcohol including amine;
derivative of C-8 to C-18 linear alcohol including carboxylate;
sulfonate;
polyethylene glycol;
5 silicone;
siloxane;
dinonyl phenol;
ethylene oxide block copolymer; and
propylene oxide block copolymer.

10

143. The method of claim 7, wherein the tubular members comprise wellbore casings.

144. The method of claim 7, wherein the tubular members comprise underground
pipes.

15

145. The method of claim 7, wherein the tubular members comprise structural
supports.

146. The method of claim 7, wherein the lubricant comprises a metallic soap.

20

147. The method of claim 7, wherein the lubricant comprises zinc phosphate.

148. The method of claim 7, wherein the lubricant provides a coefficient of dynamic
friction of between about 0.08 to 0.1.

25

149. The method of claim 7, wherein the lubricant is selected from the group
consisting of:

sodium stearates, calcium stearates, zinc stearates, zinc phosphate, manganese
phosphate, C-Lube-10, C-Phos-58-M, C-Phos-58-R,

polytetrafluoroethylene, molybdenum disulfide, and metallic soaps.

150. The method of claim 7, wherein the lubricant provides a sliding coefficient of friction less than about 0.20.

5

151. The method of claim 7, wherein the lubricant is selected from the group consisting of:

polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol acetate copolymers, polyvinyl vinyl acetate copolymers, polyvinyl pyrrolidone and copolymers including polyolefins, latexes, styrene butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, block copolymers including isoprene butadiene, block copolymers including ethylene, and ethylene acrylic acid copolymers.

10

15

152. The method of claim 7, wherein the lubricant is selected from the group consisting of:

20

graphite, molybdenum disulfide, lead powder, antimony oxide, polytetrafluoroethylene, and silicone polymers.

153. The method of claim 7, wherein the lubricant comprises a suspension of particles in a carrier solvent.

25

154. The method of claim 7, wherein the lubricant is selected from the group consisting of:

manganese phosphate, zinc phosphate, and iron phosphate.

155. The method of claim 7, wherein the lubricant comprises:
about 1 to 90 percent solids by volume.
- 5 156. The method of claim 153, wherein the lubricant comprises:
about 5 to 70 percent solids by volume.
157. The method of claim 154, wherein the lubricant comprises:
about 15 to 50 percent solids by volume.
- 10 158. The method of claim 7, wherein the lubricant comprises:
about 5 to 80 percent graphite;
about 5 to 80 percent molybdenum disulfide;
about 1 to 40 percent PTFE; and
about 1 to 40 percent silicone polymers.
- 15 159. The method of claim 7, wherein the lubricant comprises one or more of the
following:
ester;
sulfurized oil;
20 alkanolamides;
amine;
amine salt;
olefin;
polyolefins;
25 C-8 to C-18 linear alcohol;
derivative of C-8 to C-18 linear alcohol including ester;
derivative of C-8 to C-18 linear alcohol including amine;
derivative of C-8 to C-18 linear alcohol including carboxylate;
sulfonate;

polyethylene glycol;
silicone;
siloxane;
dinonyl phenol;
5 ethylene oxide block copolymer; and
propylene oxide block copolymer.

160. The apparatus of claim 8, wherein the tubular members comprise wellbore casings.

161. The apparatus of claim 8, wherein the tubular members comprise underground pipes.

162. The apparatus of claim 8, wherein the tubular members comprise structural supports.

163. The apparatus of claim 8, wherein the lubricant comprises a metallic soap.

164. The apparatus of claim 8, wherein the lubricant comprises zinc phosphate.

165. The apparatus of claim 8, wherein the lubricant provides a coefficient of dynamic friction of between about 0.08 to 0.1.

166. The apparatus of claim 8, wherein the lubricant is selected from the group consisting of:

sodium stearates, calcium stearates, zinc stearates, zinc phosphate, manganese phosphate, C-Lube-10, C-Phos-58-M, C-Phos-58-R, polytetrafluoroethylene, molybdenum disulfide, and metallic soaps.

167. The apparatus of claim 8, wherein the lubricant provides a sliding coefficient of friction less than about 0.20.

168. The apparatus of claim 8, wherein the lubricant is selected from the group consisting of:

5

10

15

polyacrylamide polymers, AMPS-acrylamide copolymers, modified cellulose derivatives, hydroxyethylcellulose, carboxymethyl hydroxyethyl cellulose, polyvinyl alcohol polymers, polyvinyl acetate polymers, polyvinyl alcohol acetate copolymers, polyvinyl vinyl acetate copolymers, polyvinyl pyrrolidone and copolymers including polyolefins, latexes, styrene butadiene latex, urethane latexes, styrene-maleic anhydride copolymers, viscosity index improvers for motor oils, polyacrylate esters, block copolymers including styrene, block copolymers including isoprene butadiene, block copolymers including ethylene, and ethylene acrylic acid copolymers.

169. The apparatus of claim 8, wherein the lubricant is selected from the group consisting of:

20

graphite, molybdenum disulfide, lead powder, antimony oxide, poly tetrafluoroethylene, and silicone polymers.

170. The apparatus of claim 8, wherein the lubricant comprises a suspension of particles in a carrier solvent.

25

171. The apparatus of claim 8, wherein the lubricant is selected from the group consisting of:

manganese phosphate, zinc phosphate, and iron phosphate.

172. The apparatus of claim 8, wherein the lubricant comprises:

about 1 to 90 percent solids by volume.

173. The apparatus of claim 170, wherein the lubricant comprises:
about 5 to 70 percent solids by volume.

5

174. The apparatus of claim 171, wherein the lubricant comprises:
about 15 to 50 percent solids by volume.

10

175. The apparatus of claim 8, wherein the lubricant comprises:
about 5 to 80 percent graphite;
about 5 to 80 percent molybdenum disulfide;
about 1 to 40 percent PTFE; and
about 1 to 40 percent silicone polymers.

15

176. The apparatus of claim 8, wherein the lubricant comprises one or more of the
following:

20

ester;
sulfurized oil;
alkanolamides;

amine;
amine salt;
olefin;

25

polyolefins;
C-8 to C-18 linear alcohol;
derivative of C-8 to C-18 linear alcohol including ester;
derivative of C-8 to C-18 linear alcohol including amine;
derivative of C-8 to C-18 linear alcohol including carboxylate;
sulfonate;
polyethylene glycol;

5 silicone;
 siloxane;
 dinonyl phenol;
 ethylene oxide block copolymer; and
 propylene oxide block copolymer.

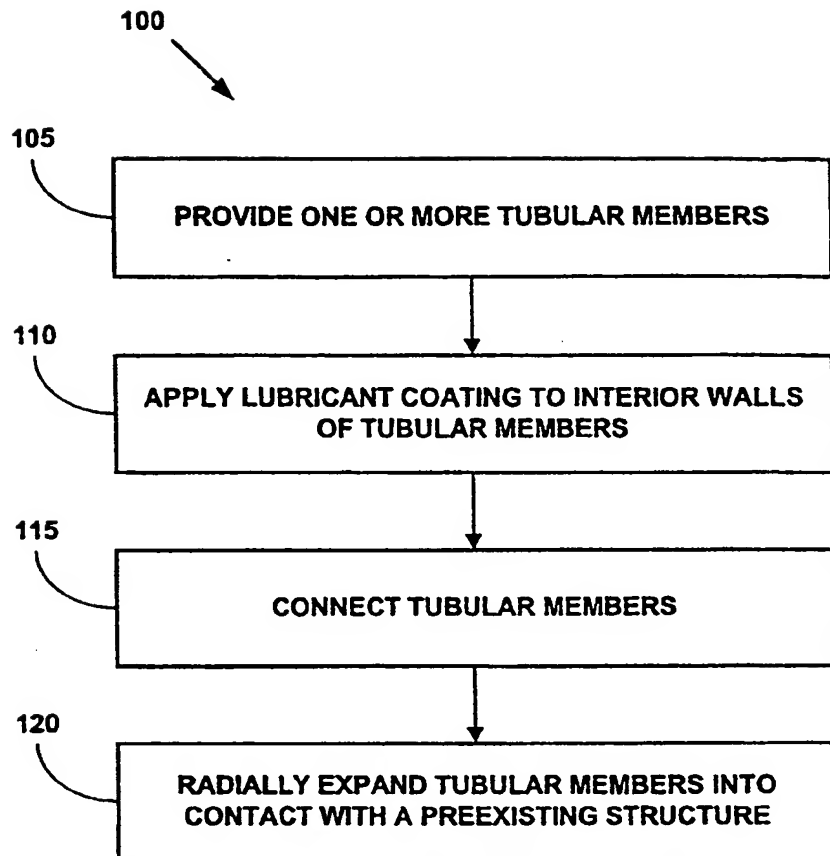


FIGURE 1

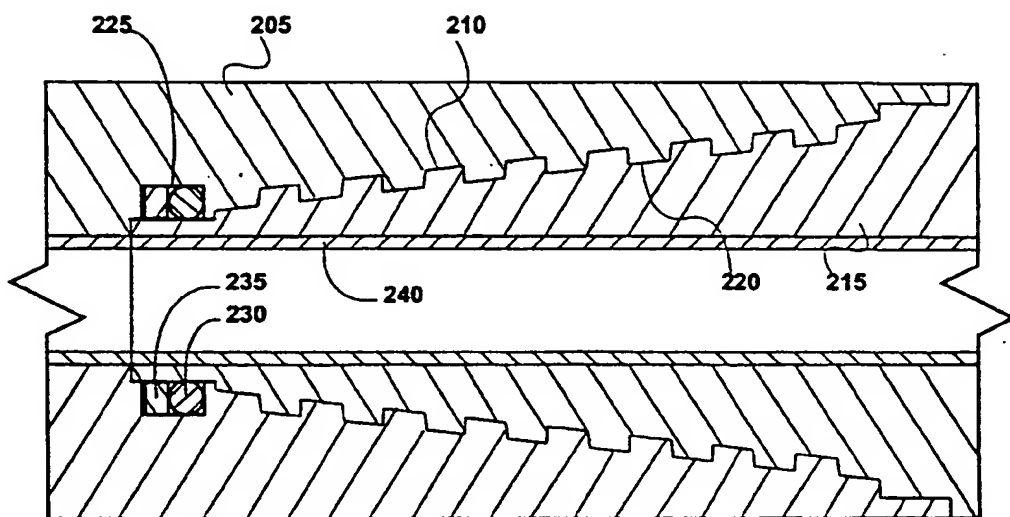


FIGURE 2

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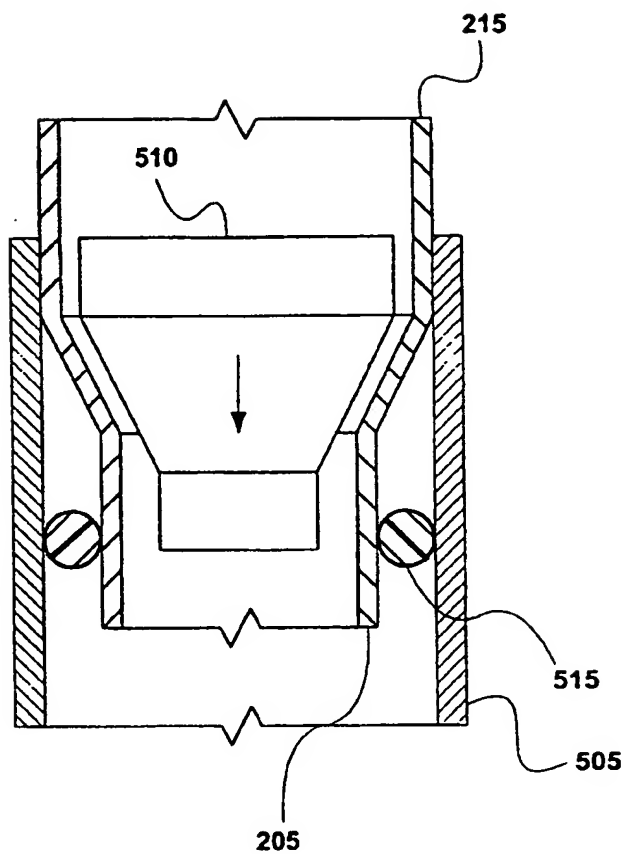


FIGURE 3

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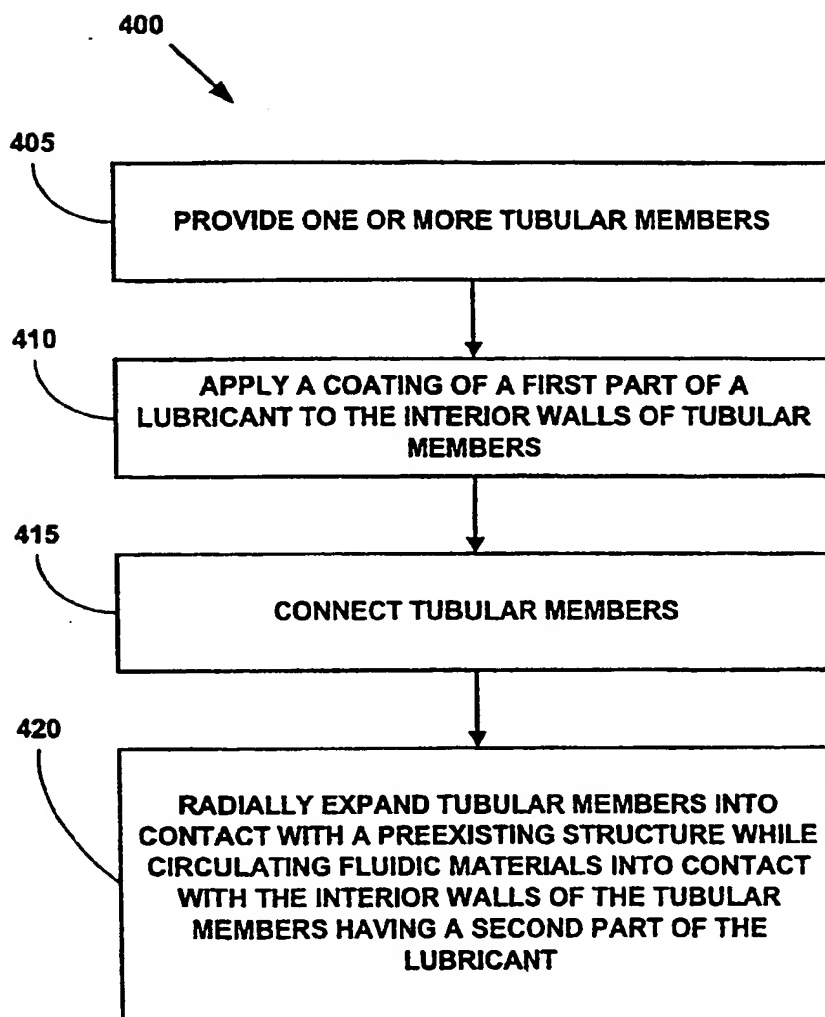


FIGURE 4

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US00/27645

A. CLASSIFICATION OF SUBJECT MATTER

IPC(7) : B23P 17/02

US CL : 138/98; 29/890.031, 890.044

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

U.S. : 138/98; 29/890.031, 890.044

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 4,573,248 A (HACKETT) 04 March 1986, col. 4, lines 41-43.	1-4
X	US 4,069,573 A (ROGERS, JR. et al) 24 January 1978, col. 4, lines 27-30.	1-4
A	US 4,413,395 A (GARNIER) 08 November 1983, entire document.	1-8
A	US 5,368,075 A (BARO et al) 29 November 1994, entire document.	1-8

☐ Further documents are listed in the continuation of Box C. ☐ See patent family annex.

* Special categories of cited documents:

"A" documents defining the general state of the art which is not considered to be of particular relevance

"E" earlier documents published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"Z" document member of the same patent family

Date of the actual completion of the international search

02 DECEMBER 2000

Date of mailing of the international search report

29 DEC 2000

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